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THE UNIVERSITY OF ALBERTA

FEASIBILITY STUDY OF USING WASTE PRODUCTS FROM CHEMICAL PLANTS IN WATERFLOODING

by

©

Se Jong Song

A THESIS

SUBMITTED TO THE FACULTY OF GRADUATE STUDIES AND RESEARCH

IN PARTIAL FULFILMENT OF THE REQUIREMENTS FOR THE DEGREE

OF MASTER OF SCIENCE IN PETROLEUM ENGINEERING

DEPARTMENT OF MINERAL ENGINEERING

EDMONTON, ALBERTA

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THE UNIVERSITY OF ALBERTA

FACULTY OF GRADUATE STUDIES AND RESEARCH

The undersigned certify that they have read, and recommend to the Faculty of Graduate Studies and Research, for acceptance, a thesis entitled "Feasibility Study of Using Waste Products from Chemical Plants in Waterflooding" submitted by Se Jong Song in partial fulfilment of the requirements for the degree of Master of Science in Petroleum Engineering.

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Supervisor

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Date March 19, 1976

ABSTRACT

This study examines the possibilities of using waste products from chemical plants to improve waterflood efficiency. Displacement tests were run using the sample solutions from chemical plants to displace a heavy crude oil from artificial packs of unconsolidated sand.

The result of displacement tests showed that sample solutions having either high surfactant concentrations or high pH values, gave significant increases in oil recovery.

Samples G, E and B in brine at a concentration of one percent by weight or greater increased oil recovery significantly. However, pure sample solutions were somewhat less effective than the sample-brine mixtures.

The recovery mechanism in the successful sample floodings may involve saponification of carboxylic acids in crude oil, sharp reduction of water-oil interfacial tension and in situ emulsification. Viscous water-in-oil emulsion so formed displaces oil very efficiently with stabilized emulsion bank front, reducing viscous fingering and eventually increasing volumetric sweep efficiency.

The delayed Sample G injections into the flooded out cores increased oil recovery indicating that sample solutions can be used in tertiary recovery. However, the greater effect on recovery was noted to occur when sample

solutions were used from the early stage of flooding.

A feasibility test of slug injection was carried out. A 0.2 pore volume slug of Sample G followed by brine flooding showed practically the same recovery performance as that of continuous Sample G flood. The cost of sample flood could therefore be reduced significantly by using slugs rather than continuous sample injection.

Infrared absorption tests exhibited the presence of carboxylic acids in Lloydminster crude oil and carboxylate anions in sample solutions. The carboxylate anions are believed to be major contributors to interfacial activities.

In addition to surfactants, the presence of inorganic salts such as sodium chloride in aqueous solutions accelerated the reduction of water-oil interfacial tension. A theoretical explanation for this phenomenon is given based on Gibb's adsorption equation.

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INTRODUCTION

Waterflooding has been a dominant secondary recovery method in many areas for a long time. In western Canada more than 95% of secondary recovery projects are waterfloods and economics will probably dictate the use of water as a flooding medium in most future projects (1).

High viscosity crude oil is found in a number of sand reservoirs in western Canada. The Sparky sand in the Lloydminster area is a fine to medium grained unconsolidated sandstone (2). Several types of enhanced recovery methods attempted have proved unsatisfactory.

Primary recoveries by solution gas drive are low, averaging only 4 - 6% of the oil in place, due to the low solution gas available and the viscous nature of the oil. Total recovery by primary and conventional waterflooding is expected to be about 10% of the initial oil in place (3). In general, low oil recovery by waterflooding of heavy crude oil reservoirs is attributed to low sweep and displacement efficiencies. Sweep efficiency is primarilly affected by reservoir heterogeneities and mobility ratio, while displacement efficiency is affected by the capillary forces between fluids and rock surfaces (4).

A review of the literature indicated that certain chemicals in the water phase increase the waterflooding efficiency by controlling factors such as mobility ratio,

capillary pressure and wettability of the rock. However, the high price of chemicals and the loss of chemicals by adsorption at solid-liquid interfaces generally discourage their use. Therefore, the need for finding cheaper substitutes having the same effects is apparent.

Many intermediate and product streams within a hydrocarbon processing plant contain one or more of a variety of acidic components. Included among the acids usually present are H_2S, mercaptans (RSH), phenols, thiophenols, and naphthenic acids (5). These acids must be removed or reduced to certain specified limits for many different reasons. Sodium hydroxide solution is generally used for that purpose. Since these acids generally have undesirable, pollutant effects such as high oxygen demand, toxicity, and taste and odor, aqueous effluents containing these acids should be treated to meet the local pollution regulation before they drain into natural waterways.

However, some of these acids possess high surface activity in contact with alkaline solution. This suggests that the waste effluents may be used as additives in waterflooding processes to increase oil recovery. Therefore, it was the purpose of this study to determine if the waste effluents from chemical plants could increase the recovery of high viscosity crude oil from unconsolidated sands.

LITERATURE REVIEW

Controllable Factors Affecting Waterflooding

The success of waterflooding as a secondary recovery measure depends on a complex interaction of the various fluids and reservoir properties. While most of these properties are fixed and uncontrollable, there are some properties which can be controlled to enhance the waterflood efficiency. Among these are rock wettability, interfacial tensions and oil-water viscosity ratio.

Wettability can be defined as the tendency of one fluid to spread on or adhere to a solid surface in the presence of other immiscible fluids (6). Jennings (7) defined a preferentially water wet solid as a solid upon which the advancing contact angle in a solid-water-oil system is smaller than 90 degrees when measured through the water. Similarily a preferentially oil wet solid was defined as a solid upon which the advancing contact angle measured through the oil is smaller than 90 degrees. He found that relative permeability, capillary pressure and water floodability of natural and synthetic porous media were influenced by the preferential wettability of the solid surface.

Some investigators (8, 9, 10) have found that more oil is recovered from preferentially water-wet systems than preferentially oil-wet cores. Others (11, 12, 13) indicate

that waterflood oil recovery from cores of intermediate wettability may be greater than that from either strongly water-wet or strongly oil-wet cores. Capillary forces in water-wet systems lead to bypassing of oil in the large pores while in the oil-wet system oil is bypassed in the small pores. The importance of these forces is diminished in intermediate wettability system.

Benner et al (14) found that with all of the crude oils investigated there was a hysteresis of the interfacial contact angle. The oil water interface gave one angle against the solid when water was advancing and a different angle when water was receding. They also found that spontaneous displacement of oil by water occured only when both angles were less than 90 degrees.

A number of authors (15, 16, 17, 18) have shown that coring fluids, core handling techniques and storage can cause significant changes in the wettability of rock surfaces. The authors emphasize that special core handling techniques are required to preserve the original reservoir wettability of cores. Mungan (19) found that some originally oil-wet samples become water wet after they were exposed to air for a week. Other investigators (20) have reported cases in which air exposure resulted in cores becoming less water wet. Mungan (21) also stated that the original wettability of the weathered cores was restored upon saturating with crude and aging for two weeks at reservoir temperature.

Bobek et al (22) proposed the imbibition test as one of the means which could indicate preferential rock wettability. Imbibition has been defined by Graham and Richard (23) as the spontaneous taking up of a liquid by a porous solid. Spontaneous imbibition occurs when a fluid-filled solid is immersed or brought in contact with another fluid which preferentially wets the solid. The rate of imbibition is a function of the permeability of the porous medium, oil water interfacial tension and contact angle. In waterflooding, the capillary imbibition process dominates at very low rates while at very high flow rates pressure gradients tend to control the displacement process.

A lot of research has been done on the effect of interfacial tension on oil recovery. The effect of interfacial tension varies depending upon the wettability of the formation rock. Some investigators (24, 25, 26) have found that oil recovery by waterflooding was increased if the interfacial tension was increased in water-wet systems and decreased in oil-wet systems. Others (27, 28) attributed increased recovery in water-wet reservoirs to decreased interfacial tension due to the surfactants added to the water. Kennedy et al (29) reported that lowering the interfacial tension had a tendency toward reducing the recovery of oil and that the reduction of the surface tension of the brine had little or no effect. On the other hand, Mungan

(30) and Wagner et al (31) observed that the displacement efficiency in both water-wet and oil-wet systems could be markedly improved by a sufficient reduction in the interfacial tension between the fluid phases.

The effect of water-oil viscosity ratio on waterflooding was well described by Calhoun (32). When a viscous fluid is displaced from a capillary by a less viscous fluid, there is a tendency for the displacing fluid to take the path of least resistance at the center portion of the capillary. If the situation is reversed, a piston-like displacement occurs since the displacing fluid is less mobile than the displaced. It is the purpose of mobility control to achieve a piston-like displacement.

Jennings et al (33) and Cooke et al (34) have indicated that a favorable water oil viscosity ratio can be achieved by emulsification of crude oil in situ. They attributed the increased volumetric sweep efficiency in caustic floods to the role of the viscous, oil external phase emulsion, formed in situ. Strassner (35) found that emulsions were stabilized primarily by film-forming asphaltenes and resins containing organic acids and bases. He also found that the stability of emulsion depends upon the pH of the water phase and the crude oil viscosity.

Chemicals Used for Improving Flood Efficiency

Various chemicals have been used to increase oil recovery by controlling factors mentioned earlier. Michaels et al (36) found that waterfloods with small amounts of surfactants, which cause strong wettability reversal from water wet to oil wet, may recover as much as 65% of the normal residual oil. The use of sodium hydroxide has been reported extensively in the literature (37, 38, 39, 40, 41, 42, 43). Ehrlich et al (44) examined the applicability of alkaline waterflooding in light oil reservoirs where wettability reversal is the dominant enhanced recovery mechanism. If interfacial tension between alkaline solution and crude oil is less than the critical value determined by reservoir properties, a sodium hydroxide flood would recover oil by an interfacial tension lowering mechanism in addition to or in lieu of recovery by the wettability reversal mechanism. Jennings et al (45) suggested an alternative to the wettability reversal mechanism by which caustic injection can significantly improve the recovery of certain crude oils. The reduction of interfacial tension causes emulsification of crude oil in situ which tends to lower injected water mobility, damp the tendency toward viscous fingering, and improve volumetric sweep efficiency. Cooke et al (46) presented a different recovery mechanism. They reported that soap forming reaction of alkaline water and naturally occur-

ring organic acids results in low interfacial tension and the wettability reversal of the porous medium to preferentially oil wet under the proper conditions of salinity, pH and temperature. As a result, in situ emulsification takes place to form a water-in-oil type of emulsion which increases pressure gradients across a narrow region in the vicinity of the emulsion front. These increased pressure gradients are sufficient to overcome the reduced capillary forces and displace the oil from pore spaces.

Beckstrom et al (47) tested a number of chemicals in preliminary qualitative experiments and found that dilute solutions of salts of a strong base and a weak acid were the most effective in displacing oil from oil sand. Of all the solutions used, those of sodium carbonate, sodium bicarbonate, potassium carbonate, lithium carbonate, ammonium oxalate, sodium nitrite, sodium cyanide, sodium sulphite, sodium bisulphite, and sodium xanthate were the most successful. The relative effect of these varied, however, depending upon the crude oil employed. Everything considered, sodium carbonate was conceded to be the most satisfactory compound of all for waterflooding.

The use of detergents as additives for waterflooding has been examined vigorously by the researchers at the U.S. Bureau of Mines, and in the U.S.S.R.. By using a centrifugal test technique, Dunning, Hsiao, Johnson and Beaty (48, 49, 50) investigated a number of detergents to determine their

ability to improve oil recovery. They concluded that nonionic detergents in pure form or in built formulations appear to be the most promising waterflooding additives. "Nonionic detergents having an optimum balance of polyoxyethlene chain length (water-soluble) and alkyl phenol (oil-soluble) will displace virtually all of the oil". Generally the high cost of surfactants and their losses by adsorption at solid-liquid interfaces have discouraged their use (51, 52).

A new oil recovery method using micellar solutions was proposed by several authors (53, 54). These micellar solutions are surfactant-stabilized dispersions of oil and water, and may also contain small quantities of other additives. Micellar solutions, even in small slug sizes, are very efficient in recovering oil. The advantage of this method is two fold. One is that mobility control can be achieved by adjusting slug viscosity and the other is that surfactant loss by adsorption is minimized.

Surface Active Constituents in Crude Oil

Many investigations have been done on the naturally occurring surface active constituents in crude oils. Knowledge of these constituents in a crude oil is a requisite to understanding interfacial phenomena such as wetting, interfacial tension reduction and in situ emulsification, which may affect or govern the success of waterflooding.

Benner and Bartell (55) were probably the first to draw attention to the effect of polar impurities in crude oil on the wettability of rock. They mentioned that the normally hydrophilic rock material may be greatly altered in nature, or even caused to become hydrophobic, through adsorption of basic or acidic polar impurities from crude oil. Bartell and Niederhauser (56), through their study on Rio Bravo (California) crude, found that a solid film formed at crude oil-water interfaces. The film-forming material was highly surface active and closely related to resins and asphaltenes in crude oil.

Reisberg and Dosher (57) also observed rigid films at the interface between crude oil (Ventura, California) and water. The formation of these interfacial films resulted in the adhesion of crude oil to a water-wetted surface, whereas it did not adhere as readily to a dry sand surface. In order to eliminate the possibility that these observations were influenced by atmospheric contamination, anaerobic conditions were maintained during crude sampling and laboratory measurements and no decrease in rigid film forming characteristics was noted. It was observed that, at a pH in excess of 8, rigid film formation became negligible. The authors separated these interfacially active materials which appeared to be related to the resins and asphaltenes. Infrared absorption analysis also indicated that these were very rich in ester and carboxylic groups.

Carboxylic acids have been recognized for many years as constituents of certain crude oils. Sachanen (58) indicated that oxygen compounds naturally occurring in crude oil are acids, and classified the oxygen compounds present in petroleum oil as fatty acids, naphthenic acids, phenols, and resinous and asphaltic compounds. The naphthenic acids differ from fatty acids in their cyclic structure. But both of them are carboxylic acids. Seifert and Howells (59) succeeded in the isolation and identification of carboxylic acids from Midway Sunset (California) crude oil. They found that this oil contained 2.5 weight percent carboxylic acids which, in the presence of aqueous alkali, were interfacially active. Seifert (60), in his subsequent paper, concluded that phenols have a diminishing effect on the interfacial activity of the carboxylic acids.

The presence of porphyrin complexes in crude oil has been confirmed by many investigators (61, 62, 63, 64). Porphyrins are carboxylated or decarboxylated heterocyclic compounds. Dunning (65) has found that porphyrins and metal porphyrin complexes often exhibit strong interfacial activity and film forming characteristics. Dunning et al (66) isolated porphyrin constituents in a free form by a hydrobromic-acetic digestion. They found that the interfacial activities and film forming tendencies of several petroleum extracts generally parallel the porphyrin contents of these

extracts. They concluded that the metal-porphyrin complexes in petroleum are major contributors to interfacial activity and film forming tendency.

Naphthenic acids are the most abundant carboxylic acids in crude oils. The extensive research on naphthenic acids has been well described in detail by Lochte and Littman (67, 68). Dodd (69) attributed film forming characteristics of crude oil to naphthenic acids. These acids, in combination with connate waters, form soaps which hydrolize to varying degrees depending on the salt content and pH of the water. "Hydrolysis of naphthenic acids soaps would form a complex including free acids, soaps and acid anion, and such a complex probably forms the backbone of the interfacial film".

THEORY

Gibb's Adsorption Equation

The general expression for a reversible change in free energy of a multicomponent, two phase system is given by the following relationship

$$dF = - SdT + VdP + \Sigma\mu_i dn_i + \gamma dA \quad * \qquad 1$$

The change in surface free energy will be given by

$$dF^s = - S^s dT + \Sigma\mu_i dn_i^s + \gamma dA \qquad 2$$

Since the surface contribution to the volume is negligible, the quantity VdP was omitted. If the two phase system is enlarged at constant P, T, and μ_i, equation 2 may be integrated to yield the expression

$$F^s = \Sigma\mu_i n_i + \gamma A \qquad 3$$

Total differentiation of equation 3 gives

$$dF^s = \Sigma\mu_i dn_i^s + \Sigma n_i^s d\mu_i + \gamma dA + Ad\gamma$$

By comparing this result with equation 2, we find that

$$S^s dT + \Sigma n_i^s d\mu_i + Ad\gamma = 0$$

If we divide each term by the surface area, A, the familiar

* Symbols are listed and identified in the Nomenclature.

Gibb's adsorption equation

$$d\gamma = - S^s dT - \Sigma \Gamma_i d\mu_i$$

is obtained where $\Gamma_i = \frac{n_i^s}{A}$ is an adsorption density.

Since we are mainly interested in constant temperature processes, the Gibb's equation can be simplified as follows

$$d\gamma = - \Sigma \Gamma_i d\mu_i \qquad (T = \text{const.}) \qquad 4$$

The adsorption density of the i-th component relative to that of component 1 is defined by the relation

$$\Gamma_i = -\left(\frac{\partial \gamma}{\partial \mu_i}\right) T, \text{ all } \mu\text{'s except i and } \mu_1 \qquad 5$$

For any component,

$$\mu_i = \mu_i^{\circ} + RT \ell n a_i$$

Then equation 5 becomes

$$\Gamma_i = - \frac{1}{RT}\left(\frac{\partial \gamma}{\partial \ell n a_i}\right)$$

The adsorption density, Γ_i will be positive if the concentration coefficient of surface tension $(\partial\gamma/\partial \ell n a_i)$ is negative. It will be negative if the surface tension is increased by addition of component, i. The adsorption density is determined by the slope of the surface tension versus log

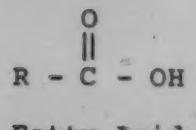
activity curve if the surface tension can be determined by experiment.

Properties of Carboxylic Acids

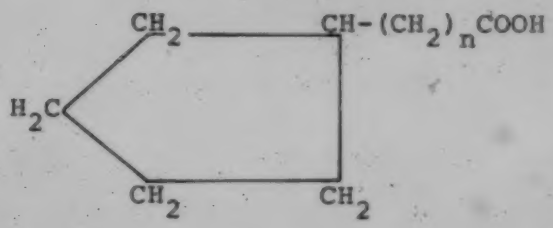
Among petroleum acids, carboxylic acids are generally believed to be the major contributors to interfacial activity (70, 71, 72, 73).

A. Structure

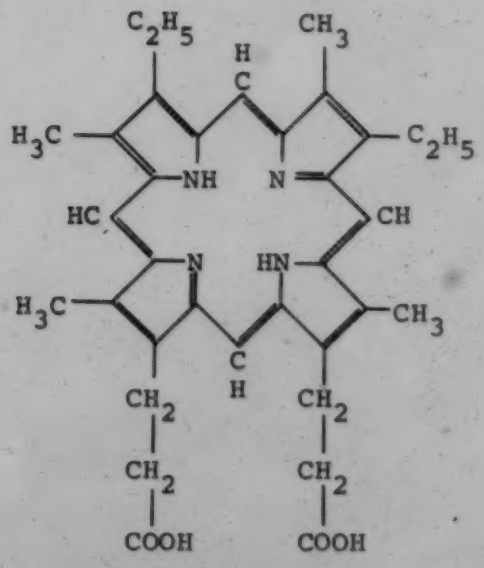
The typical structural formula of various carboxylic acids may be expressed as follows:



Fatty Acid



Naphthenic Acid



Mesoporphyrin IX

Fatty acids are the typical carboxylic acids with aliphatic alkyl groups. Naphthenic acids consist of cyclopentane derivatives in which the carboxyl group links mostly to a paraffinic side chain. Porphyrins have a heterocyclic structure with two carboxyl groups attached.

Carboxylic acids are composed of two segregated portions: One is a polar carboxyl group, COOH, which has sufficient affinity for the aqueous phase, and the other is a nonpolar alkyl group, R, which is rejected by the aqueous phase, due to its lack of affinity for water molecules. Because of this hydrophilic property of carboxyl groups and hydrophobic property of nonpolar alkyl groups, carboxylic acids concentrate at water-oil interfaces in such a manner that the alkyl group lies in the oil phase with the polar carboxyl group exposed to the water phase. Consequently, the concentration of carboxylic acids at the water-oil interface results in the reduction of the interfacial tension.

Carboxylic acids, like inorganic acids, are neutralized by bases such as sodium hydroxide or potassium hydroxide with the formation of soaps.

$$RCOOH + NaOH \rightleftharpoons RCOONa + H_2O$$

Sodium carboxylates dissolve in aqueous solutions in the forms of ions, $RCOO^-$ and Na^+.

Since the hydration energy of $RCOO^-$ is stronger than that of RCOOH, carboxylate anions would exhibit higher

interfacial activity than their carboxylic acids. Therefore, interfacial tension reduction between oil and water depends upon dissociation of carboxylic acids in an aqueous solution.

B. Dissociation

The solubility of alkali salts of carboxylic acids depends very much on the hydrolysis of the carboxylate ion:

$$RCOO^- + H_2O \rightleftharpoons RCOOH + OH^-$$

Hence, the concentration of carboxylate anion is equal to:

$$[RCOO^-] = \frac{[RCOOH][OH]}{K_h}$$

or $$[RCOO^-] = \frac{[RCOOH]}{K_h} 10^{(pH - 14)} \quad \text{(mole/liter)} \quad (74)$$

This equation shows that the concentration of carboxylate ions in a solution depends upon the pH of the solution. The concentration of carboxylate anions increases as the pH of the solution is increased.

C. Micelle Formation

About 650 calories of energy is evolved when one mole of CH_2 group is removed from water (75). Therefore, micelles form as the result of the gain in energy occasioned by removing hydrocarbon chains from the surrounding water and bringing them in contact with each other in micelles.

Free energy considerations require an arrangement of the agglomerate in aqueous solution in a manner that will expose the polar heads of the surface active ions and molecules to water, with minimum contact between the paraffin chains and water molecules.

The size and shape of the micelle is determined by the equilibrium between the attractive forces among hydrocarbon chains and the repulsive forces among the polar heads of the surfactant (76).

The concentration of surfactant at which the concentration of micelles suddenly becomes appreciable is refered to as the critical concentration for micelle formation or cmc. At concentrations greater than the cmc value, the interfacial tension between water and oil does not decrease further with an increase in surfactant concentration. However, surfactant solution, above the cmc, is capable of dissolving considerable quantities of various oil components that are quite insoluble in pure water.

D. Solubilization

Many organic substances that are not very soluble in water dissolve to a considerably greater extent in micellar solutions of surface active material. The increased solubility of the compound, due to the presence of micelles, is termed solubilization (77). Solubilization is attributed to molecular association of the material being solubilized

with the hydrophobic portion of the surfactant. By this solubilizing action which incorporates non polar hydrocarbons in the hydrocarbon interior of the micelles, the micellar solution can displace oils miscibly in porous media. The solubilization limit for a liquid can be detected by the increase in turbidity upon further addition of the solubilizate.

E. Emulsification

In situ emulsification often encountered in waterflooding is mainly due to mechanical dispersion of one phase in the other and in part due to spontaneous emulsification in the presence of surfactants.

Mechanical dispersion based on the mechanism elucidated by Joseph Plateau is well described by Bikerman (78). Consider the water entering into a porous medium. The water drop is extended to form a cylinder or spheroid by being squeezed into a capillary tube. This becomes unstable as soon as its length exceeds its circumference, and two spherical drops form. This process takes place because, above a definite ratio of length to radius, at least some indentations on the cylinder surface are developed due to the irregular surface of the capillary tube and the opening smaller than the drop. Consequently, capillary pressure near the bottom of the indentation is greater than that far from it. This capillary pressure difference drives the

liquid away from the indentation, which grows deeper and deeper until the cylinder is snapped in two. Rupture occurs spontaneously when the surface area of the system steadily decreases in going from a slight indentation to complete separation into two drops because the interfacial energy of the separate spherical droplets is less than that of the initial elongated body.

If oil and water containing surfactants are brought quietly into contact, spontaneous emulsification may occur on one or both sides of the interface (79). The total interfacial tension of a water oil system with emulsifiers can be defined by

$$\gamma_i = \gamma_{ow} - \pi$$

where γ_{ow} is the oil-water interfacial tension in the absence of the emulsifying agent and π is the spreading pressure of the added emulsifiers at the oil-water interface.

In order to form micro emulsions it is necessary that the concentration of emulsifiers be greater than that required to reduce the oil-water interfacial tension to zero (80). This indicates that the interfacial tension γ_i must have a negative value and that the area of the interface tends to increase spontaneously. This would cause droplets to break up spontaneously, stabilize the dispersed phase, and prevent phase separation.

The role of an emulsifying agent is not only to sustain the emulsion formed by mechanical dispersion but also to give rise to spontaneous emulsification.

Einstein proposed an equation relating the viscosity of a suspension with that of the suspending liquid and the volume fraction of dispersed rigid spheres (81):

$$\mu = \mu_e(1 + 2.5\phi)$$

where μ is the viscosity of the emulsion, μ_e is the viscosity of the external phase, and ϕ is the volume fraction of internal phase. This is a limiting law, whose validity increases as ϕ approaches zero. Simon et al (82) used a similar but more general equation originally proposed by Richardson:

$$\mu = \mu_e \varepsilon^{k\phi}$$

The viscosity of an emulsion is primarily a function of oil-water ratio and temperature, but is essentially independent of the viscosity of the internal phase. In general, it can be said that the viscosity of an emulsion is increased if the volume fraction of the internal phase is increased, if the globule size is reduced, or if the globule size distribution is made more uniform.

Capillary Force

The general relationship between pressure drop across

a curved boundary and interfacial tension is given by the following equation.

$$P_c = \gamma_{ow}\left(\frac{1}{r_1} + \frac{1}{r_2}\right)$$

Craig (83) defines capillary pressure in porous media simply as the pressure difference existing across the interface separating two immiscible fluids, one of which wets the surfaces of the rock in preference to the other. For simplicity, the analogy with a bundle of capillaries has often been used in the study of capillary phenomena in a porous medium as the reservoir fluids exist in spaces which are capillary in size. The capillary pressure in a narrow circular tube filled with oil and water is expressed by the equation

$$P_c = P_o - P_w = \frac{2\gamma_{ow}\cos\theta}{r}$$

This theoretical equation states that the capillary pressure can have either a positive or a negative value, depending upon the wettability preference. If the contact angle is less than 90 degrees, the system is preferentially water wet and will have positive capillary pressure, and if the contact angle is higher than 90 degrees, the system is preferentially oil wet with negative capillary pressure.

It also states that the capillary pressure is a direct function of interfacial tension. Therefore, capillary forces can be reduced by decreasing water oil interfacial

tension.

Waterflooding

The fractional flow equation describing horizontal linear flow of oil and water in porous media is:

$$f_w = \frac{1 + \frac{K\, K_{ro}}{V_t\, \mu_o}\left(\frac{\partial P_c}{\partial L}\right)}{1 + \frac{\mu_w\, K_o}{\mu_o\, K_w}}$$

The derivation of this equation is a straight forward process applying Darcy's equation for two phase flow in horizontal linear porous media. The variables affecting fractional flow of water are capillary pressure gradient along the direction of flow, relative permeabilities of oil and water, fluid velocity, and viscosities of oil and water.

The effect of capillary pressure on fractional water flow depends upon the wettability and fluid saturation states in porous media. Positive capillary pressure in a water wet system gives rise to a suction of water into the pore spaces. Thus the high capillary pressure is generally desirable to displace oil from a porous medium. However, movement of non-wetting phase, oil, in an insular saturation state is resisted by capillary pressure. This is called the Jamin effect (84) which can be a factor in the residual oil saturation in a water wet system. The capillary pressure, in this case

is required to be low to minimize the Jamine effect and displace the residual oil from a water wet system. Negative capillary pressure in an oil wet system apparently resists water enchroachment into the system. Therefore, the capillary pressure should be low to increase the oil recovery from an oil wet reservoir.

For high flow rate and high oil viscosity, the effect of capillary pressure on fractional flow is minimized. Therefore, the fractional flow behaviour depends upon oil water mobility ratio which is a function of the relative permeabilities and the viscosities of water and oil.

Relative permeabilities are the composite function of pore geometry, wettability, fluid distribution, and saturation history (85). Wettability is a highly important factor affecting water-oil relative permeability characteristics. As the preferential wettability of a porous medium changes from oil wet to water wet, the oil relative permeability increases and that of water decreases.

For a given set of water-oil relative permeabilities, fractional flow depends upon the magnitude of oil and water viscosities. Regardless of the system's wettability, a higher oil viscosity results in less efficient displacement (86). That is, there is a lower recovery at any water-oil ratio and an increased injected water volume is required to achieve that recovery.

A review of the theoretical aspects of water flood-

ing suggests that the control of properties such as wettability, capillary pressure, and water and oil viscosities by chemicals can increase waterflood efficiency and ultimate oil recovery from a porous medium.

MODEL SCALING

Since the flooding behaviour under field conditions is usually stabilized, laboratory displacement tests must be properly designed or "scaled" to eliminate the effects of viscous fingering and capillary end effects (87, 88, 89, 90).

On the basis of the theory developed by Rapoport and Leas (91) it is recognized that the flooding behaviour is dependent upon the length of the system, rate of injection and fluid viscosity. It is also found that end effects could be eliminated if the scaling coefficient $LV_t\mu_w$, was greater than a critical value of 1.

In the present study two injection rates, 30 and 40 cc/hour, were used. The scaling coefficients for these rates were 1.97 and 2.62 cm^2-cp/min respectively. These rates were considered sufficiently high to eliminate capillary end effects.

Kyte et al (92) found that a water flood is stabilized if the capillary pressure gradient in the direction of flow is small compared to the imposed pressure gradient. Maximum total pressure drop across the core necessary to achieve stabilization was found to be of the order of 50 psi regardless of the core length. The initial pressure applied in the present study was about 97 psi.

The effect of viscous fingering will be appreciable when the mean distance between fingers is less than the

cross-sectional dimension of the core. To scale for viscous fingering effects, the scaling coefficient developed by Chuoke et al (93) was utilized. This coefficient may be written as

$$\frac{\psi_{cr}}{h} = c\sqrt{\frac{3\,\gamma_{ow}\,K}{V_t(\mu_o - \mu_w)\,h^2}}$$

Chuoke et al found that if the scaling coefficient, ψ_{cr}/h, is much less than 1.0, there exist a large number of fingers in the model and consequently production behaviour is insensitive to viscous fingering. If the scaling coefficient is much greater than 1.0, no fingers will occur and the system has essentially a stable behaviour leading to high recovery. If the scaling coefficient is of the order of 1.0, production behaviour is unstable and can be seriously affected by variations in the value of mean finger distance.

For the core used in the present work and rates selected, the maximum viscous scaling coefficient was 0.043. Therefore, viscous fingering may occur in the core but production behaviour would be relatively stable and insensitives to the viscous fingering effect.

EXPERIMENTAL EQUIPMENT AND PROCEDURES

Materials

Two sand samples were used during this study and are identified in Table A - 1 in Appendix A. Sand 1 was unconsolidated Sparky sand from the Lloydminster area. Sand 1 was cleaned using a technique similar to that described by Collins (94). The sand was washed with hot tap water and flushed with Varsol until no further traces of oil staining were evident. After Varsol had evaporated, the sand was dried in a drying oven at 210° F for 10 hours. The particle size distribution of Sand 1 is shown in Figure 1. Sand 2 is a 80 - 120 mesh clean Ottawa sand.

Lloydminster crude oil, treated only for the removal of water, was 16.7° API and the basic sediment and water content was 0.1% by volume. The viscosity of this crude oil was 2800 cp at 72° F. The viscosity of crude oil was measured with a Weissenberg Rheogoniometer. The crude oil density was determined by use of a pyconometer.

For bench tests and imbibition tests, a Varsol-crude mixture was prepared by mixing 6 parts by volume of Varsol with 1 part by volume of crude oil.

An artificial brine was prepared by dissolving 84.84 grams of sodium chloride in distilled water to make a liter of solution. This concentration matched the chloride ion content of a Lloydminster field water sample described by

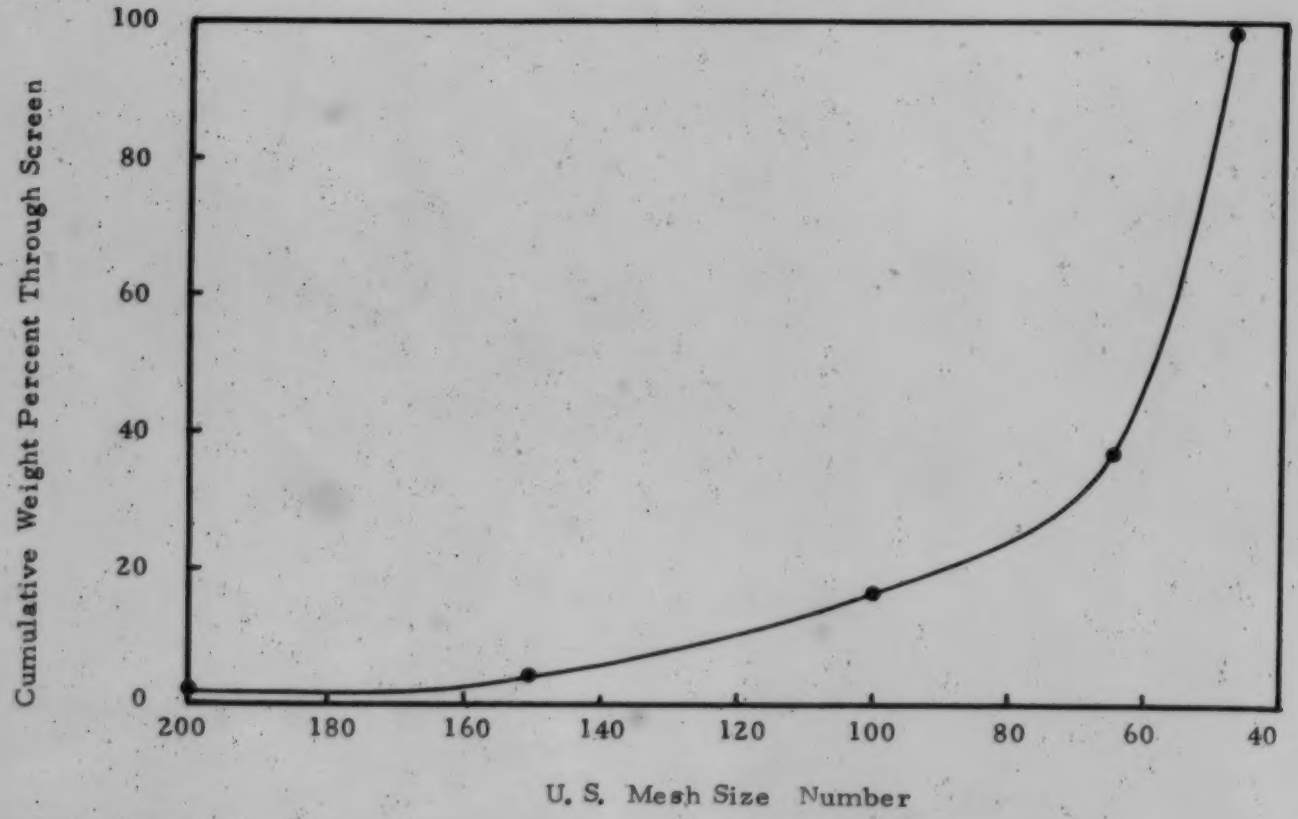


FIG. 1 - PARTICLE SIZE DISTRIBUTION OF SPARKY SANDS FOR CORE PACKING AND TESTING

Collins (95).

Samples A - G were waste effluents from various chemical plants and their properties are summarized in Table A - 3 in Appendix A. The chemicals used in the preparation of various solutions were regeant grade and are identified in Table A - 4.

Infrared Absorption Tests

Infrared absorption tests were conducted to examine naturally occuring petroleum acids in crude oil and surfactant dissolved in various samples.

10 ml of crude oil was mixed with 20 ml of 1% NaOH solution in a 50 ml centrifuge tube with a screw cap. The mixture was shaken vigorously with a mechanical device for about an hour and allowed to stand for a day to separate the water from the oil phase. The water phase was withdrawn using a syringe and acidified with HCl to convert the ionized petroleum acids into molecular form. Petroleum acids in their molecular form are dissolved readily in the CCl_4 phase. Spectrograde CCl_4 was added to this solution. This CCl_4-solution mixture was shaken for about an hour. During this time, most of petroleum acids were transfered into the CCl_4.

An infrared spectrum of this CCl_4 extract was taken using a Perkin Elmer 221G double beam spectrophotometer. An NaCl cell with a path length of 0.5 cm was used.

A reference cell having the same dimension was filled with CCl_4 to eliminate errors resulting from possible impurities in the CCl_4. The use of the reference cell also improved the resolution of the overall infrared spectrum.

Seven samples from chemical plants were prepared for infrared analysis in a similar manner.

Bench Tests

A simple bench test technique was used to determine qualitatively the wettabilities of the sands. A procedure similar to that proposed by Bobek et al (96) was utilized.

To test for wettability, a thin layer of dry sand was spread on a glass plate. Droplets of oil or water were placed on the surface of the sand. The rate of movement of the fluid into sand was observed using a 10 power magnifying glass. To test for preferential water wettability, a thin layer of dry sand on a glass plate was saturated with oil. Droplets of water were then placed on the sand and the rate of water movement into the sand was observed.

If the water moved readily into the sand and displaced oil from the surface of the sand grains, the sand was considered preferentially water wet.

To test for preferential oil wettability, dry sand, in stead of sand initially saturated water, was used. Because oil has a tendency to spread on a water surface in a monolayer, it was difficult to discern whether oil wetted

the sand or simply spread on the water surface when water saturated sand was used.

Cell Imbibition Tests

Imbibition tests were conducted with an apparatus similar to that used and described by Bobek et al (97). Lucite cylinders fitted with 200 mesh screens at the bottom end were packed with unconsolidated sand by tapping the bottom of the cell until no further compaction was visually discernible. The cylinders were weighed and evacuated in a vacuum cell and saturated with a saturating fluid under vacuum. The saturated cylinders were weighed. The pore volume of unconsolidated sand was calculated by weight difference using the density of the saturating fluid.

The saturated cell was placed in a vertical position in the imbibition apparatus and the fluid to be imbibed was introduced into the apparatus until the cell was completely immersed. The volume of saturating fluid displaced from the cylinder was measured. The imbibition tests were terminated when the volume of saturating fluid displaced showed little or no change over a period of several hours.

Fresh fluids and clean sands were used during successive imbibition tests. The imbibition apparatus was cleaned thoroughly after each test to avoid possible contamination from previous tests.

Interfacial Tension Test and pH Measurements

A Cenco du Nuoy tensiometer Model 70545 with a platinum ring was used for making surface and interfacial tension measurements. The standard method of testing for interfacial tension of oil against water by the ring method ASTM D971 - 50 was employed.

All tension measurements were carried out at room temperature maintained within 3° F difference for each set of tests. The temperature range for the complete series of tests was 72° F to 80° F.

The measured surface and interfacial tension readings were corrected using the correction factor developed by Zuidema and Water (98). This factor may be expressed as

$$(F_c - e)^2 = \frac{4g}{\pi^2 R_r^2} \times \frac{T_a}{D - d} + C_t$$

The correction factors were calculated using a computer.

The pH measurements of various solution were made using a Beckman Model N pH meter with a glass reference electrode and a Beckman E - 2 glass electrode.

Displacement Tests

The core holders containing the unconsolidated sand were stainless steel models designed for high pressure flooding with corrosive chemical solutions. The internal

dimensions of the core holders were 6.0 inches length and 0.87 inches diameter.

The empty core holders including screens and end plates were weighed on a sensitive beam balance. Stainless steel screens of 200 mesh were placed between the sand and the end plate to prevent shifting of the sand and plugging of the outlet lines. The core holder was placed in a vertical position and an electric vibrator was attached to the core holder. Unconsolidated sand was poured slowly into the core holder while the vibrator was on. The procedure was continued until the core holder was full and no further compaction of the sand was evident. The upstream end of the core holder was fitted with a 200 mesh screen and then screwed on the core holder tube.

The packed core holder was weighed and mounted in the saturating apparatus shown in Figure 2. The core was evacuated and saturated with artificial brine. The brine permeability of the core was calculated during this process by measuring flow rate, and pressure drop across the core and applying a Darcy linear flow equation. The saturated core was then reweighed and the volume of the brine in the core was calculated from the weight difference between the dry sand and the saturated sand by using brine density. The pore volume of the core was determined since it is equivalent to the volume of brine in the core. Knowing the bulk volume of the core holder, 58.4 cc, and the pore volume

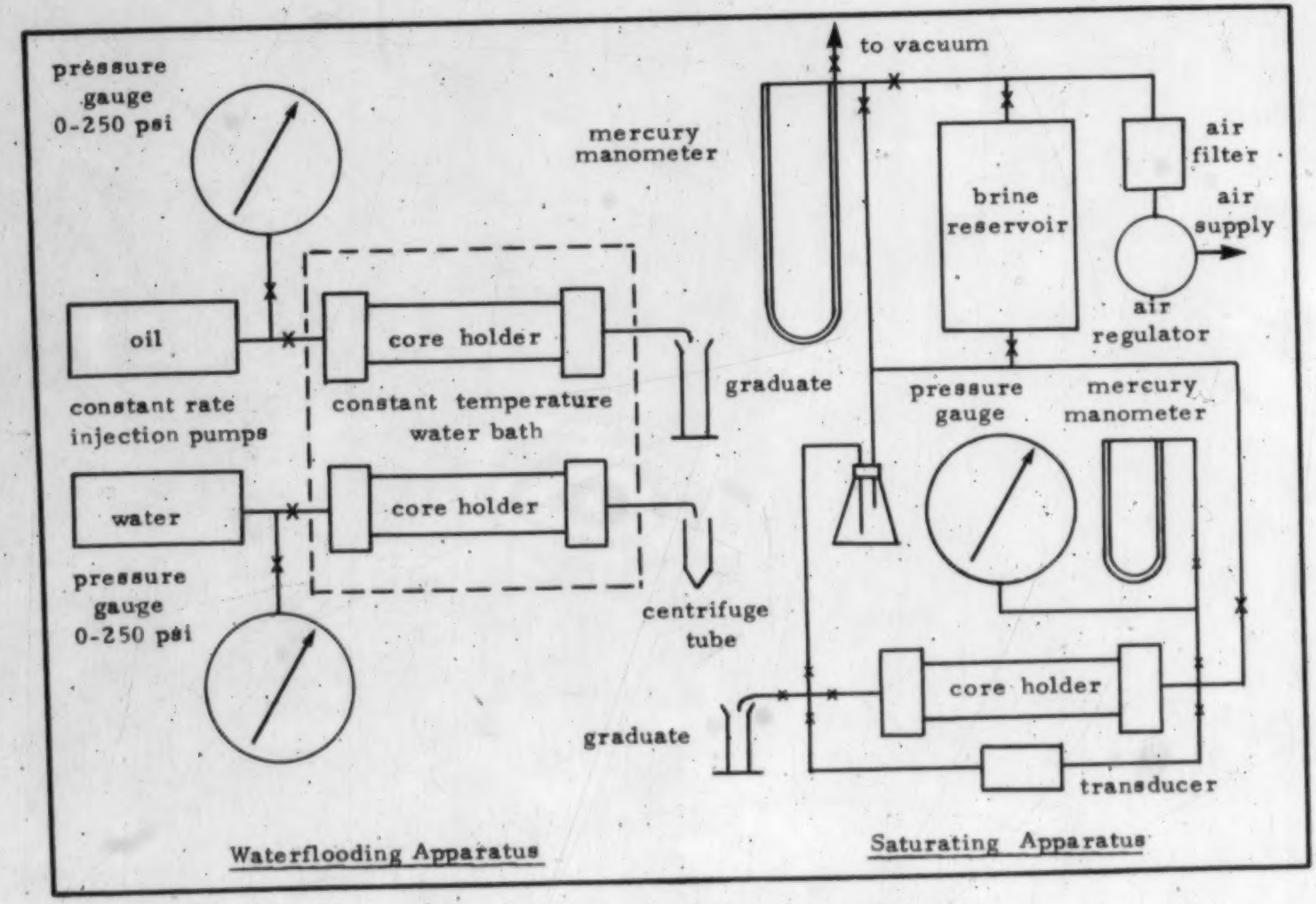


FIG. 2 - SCHEMATIC DIAGRAM OF DISPLACEMENT AND SATURATING EQUIPMENT FOR SAND CORE PACKS

of the core, the porosity of the core was calculated.

After the core properties had been measured, the core was connected to an oil and water flooding apparatus and immersed in a constant temperature water bath thermostatically controlled to within 1° F. Calibrated Heise gauges were connected to the upstream end of each core holder to measure the upstream flowing pressures. Short down stream outlets on each core minimized outlet volume corrections and eliminated the need for down stream pressure taps. The core was then saturated with crude oil using a Ruska pump. About 1.5 pore volumes of oil were injected into the core to ensure that an irreducible water saturation was attained. The volume of brine produced during the oil flood was measured and the initial water saturation was calculated. The initial oil in place was determined since it is equivalent to the volume of brine produced.

The oil saturated core was flooded with brine or chemical solutions at a constant injection rate of 30 or 40 cc per hour. The produced oil were recovered in 15 ml graduated centrifuge tubes and were centrifuged to separate the water and oil phases. Most of the oil was produced as an emulsion after water breakthrough.

A demulsifier, Visco 507, was used to break the emulsion produced. To facilitate the demulsification process, small amounts of Varsol were added to the emulsion prior to introducing the Visco 507. Two or three drops of Visco 507

was then sufficient to break the emulsion.

The volumes of oil and water were measured by a material balance on the effluent fluids. Accurate measurement of effluent is very important as the accumulation of small errors from misreading the scales may become significant. The effluent volumes were measured to within 0.05 cc. The cumulative error was found to be insignificant at this level of accuracy.

The pressure performance of waterflooding was recorded together with oil recovery. All displacement tests were conducted at 80° F. The core holders were repacked with clean sand after each test to eliminate the possibility of sand wettability being altered by previous tests.

RESULTS AND DISCUSSION

Infrared Absorption Analysis

The purpose of infrared analysis in this study was to qualitatively determine the presence of petroleum acids which, in contact with alkaline solution, exhibit high interfacial activity. Among these are the carboxylic acids, phenols and mercaptans. These petroleum acids have been reported in the literature to show interfacial activity.

Figure 3 shows infrared absorption spectra of the Lloydminster crude oil for the frequency range 3800 - 1500 cm^{-1}. A sharp absorption peak at the frequency, 1710 cm^{-1} is the typical spectrum of carboxylic acid, which is attributable to the C=O stretching vibration of the carbonyl group. The carbonyl frequencies of carboxylic acids appear in much the same spectral region as aldehydes and ketones (99). However, the carbonyl peak at 1700 cm^{-1} in the present study of the crude oil is regarded as that of carboxylic acids since no other oxygen compounds, such as alcohols, ketones, aldehydes etc., have been detected in crude oils or in cracked products (100).

The low intensity but sharp absorption peak in the frequency range 1740 - 1750 cm^{-1} may be attributable to the C=O stretching vibration of carboxylic acids or esters.

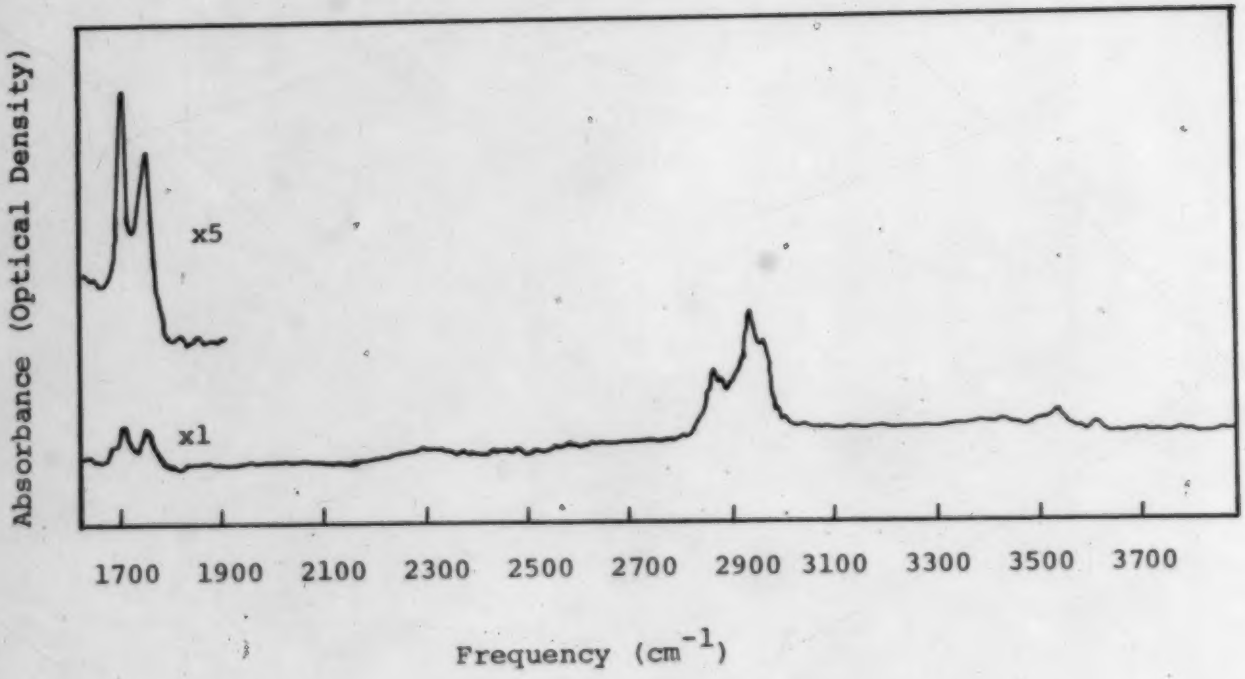


FIG. 3 - INFRARED SPECTRA OF LLOYDMINSTER CRUDE OIL

Absorption bands at 3700 and 3600 cm^{-1} are regarded as the spectra of the OH stretching vibration which may be related to water and phenols respectively.

The spectra of the C-H stretching vibration in a hydrocarbon are shown over the range 3000 -2800 cm^{-1}. Two absorption bands at 2920 and 2850 cm^{-1} are related to the C-H stretching vibration for methylene groups ($-CH_2-$). The absorption bands at 2950 and 2870 cm^{-1} represent the anti-symmetry and symmetry C-H stretching vibration bands of the terminal methyl groups ($-CH_3$) in a hydrocarbon chain. Therefore, the presence of hydrocarbons, regardless of their functional groups, can be directly detected with these C-H stretching bands.

Seifert et al (101) reported the presence of carboxylic acids at 1710 cm^{-1} and phenols at 3610 cm^{-1} in the infrared analysis of a California crude oil. These absorption bands for carboxylic acids and phenols are well matched with those of the present work. The infrared spectra of oleic acid which is one of the typical carboxylic acids show the characteristic absorption band of carboxylic acids at the frequency 1710 cm^{-1} (see Fig. 4). Two relatively weak absorption bands at 3000 and 3525 cm^{-1} may be attributed to the OH stretching vibration of carboxylic acids.

The infrared test indicates that the Lloydminster crude oil contains carboxylic acids.

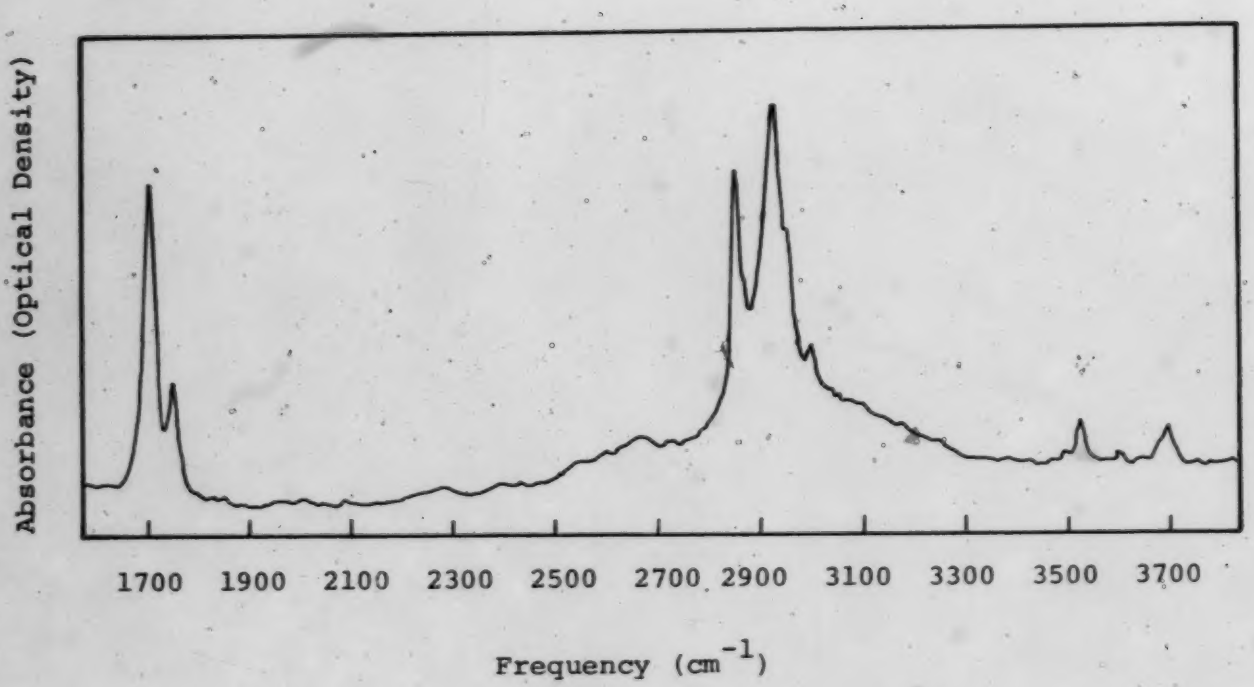


FIG. 4 - INFRARED SPECTRA OF OLEIC ACID

Infrared analyses of various sample solutions were done to determine whether the sample solutions contain organic surface active materials.

Infrared absorption spectra of Sample G are shown in Figure 5. Sample G shows the typical C=O stretching band of carboxylic acids at 1700 and 1740 cm^{-1}, and the OH stretching bands of carboxylic acids at 3000 and 3525 cm^{-1}. A high intensity absorption band at 2330 cm^{-1} is not fully identified but seems to be related to the -SH stretching vibration of mercaptans (RSH). Absorption spectra of Sample G are most well matched with those of the crude oil and pure oleic acid.

Sample E showed high intensity C=O and OH stretching bands of carboxylic acids at 1740 and 3530 cm^{-1} respectively . The infrared spectra of Sample E without acidification was taken to determine whether the high intensity peak at 1740 cm^{-1} is due to carboxylic acids or ketones. The lower members of the ketone series are freely soluble in water due to coassociation with water. Based on the fact that CCl_4 readily dissolves ketones but not carboxylate anions, a CCl_4-Sample E mixture was prepared without acidification of Sample E. An infrared test was performed on this CCl_4 extract. The result showed no C=O stretching vibration in the 1700 - 1800 cm^{-1} region. Therefore, the C=O stretching band near 1740 cm^{-1} in Sample E may be attributed to

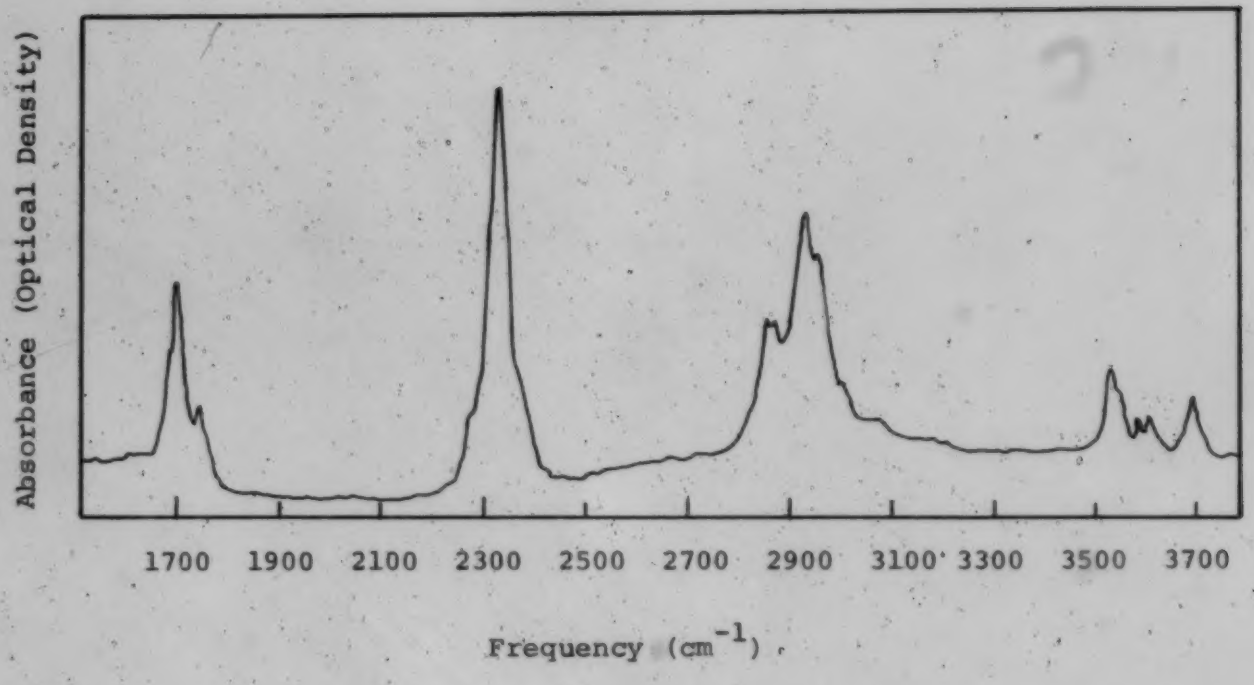


FIG. 5 - INFRARED SPECTRA OF SAMPLE G

carboxylic acids.

Sample A and D showed no detectable absorption peaks except the unknown peak at 2310 cm^{-1}. The CH bands over the range 3000 - 2800 cm^{-1} were also missing. Therefore, the hydrocarbon contents of Sample A and D are negligible.

Sample C showed a high intensity OH peak of phenol at 3600 cm^{-1} and =C-H aromatic stretching peak at 3040 cm^{-1}, which is related to the benzene ring of phenols and thiophenols. However, Sample C showed a weak C=O peak at 1700 cm^{-1}.

Sample F showed very high intensity OH and =C-H stretching bands of phenols but a weak C=O band at 1710 cm^{-1}. The medium intensity absorption band at 2590 cm^{-1} was considered to be the spectrum of mercaptans and H_2S. Sample F, in contact with HCl, produced a bad odor which can be attributed to mercaptans and H_2S.

The infrared test results indicated that Sample E, and G are rich in carboxylic anions, while Sample B, C and F have low carboxylate anion contents. On the other hand, Samples A and D contain no carboxylate anions.

Phenols were detected in all of the sample solutions. However, Sample F showed the highest phenol absorption peak.

Bench Test Results

The results of bench tests of various fluids with dry

sand and fluid saturated sand are summarized Table B - 1.

Varsol and the Varsol-crude mixture were spontaneously imbibied by all dry sands. Brine and alkaline solutions were not imbibed by dry Sand 1, while the Varsol-crude mixture was spontaneously imbibed by the dry Sand 1. This implies that the Sparky sand tested was preferentially oil wet. The spontaneous imbibition of brine by Sand 2 saturated with Varsol indicates that Ottawa sand was preferentially water wet.

Brine was not imbibed by Sand 2 which was saturated with the Varsol-crude mixture, whereas most of the chemical solutions were readily imbibed by the same sand. This may indicate that the Lloydminster crude changed the wettability of the Ottawa sand from preferentially water wet to neutral or slightly oil wet. Since wetting is a rather slow process, the wettability of a sand will depend to a great extend on the duration of contact between the sand and the saturating fluid. For example, it will be recalled that Mungan (102) required about two weeks in order to restore the original wettability of cores. On the other hand, the time of contact employed in the present study was only a few minutes in the bench test and a few hours in the cell imbibition test. It is, therefore, reasonable to assume that the wettability reversal might not have been complete. Upon reaction with alkaline solutions, this incomplete oil wet character of the Ottawa sand was easily distorted and reversed to water wet.

Consequently, the chemical solutions were readily imbibed by the sand.

Some chemical in brine solutions were imbibed by Sand 1 initially saturated with the Varsol-crude mixture. Sodium hydroxide solution and weak basic solutions such as Na_2CO_3, Na_2SiO_3 were imbibed readily by Sand 1 initially saturated with the Varsol-crude mixture, whereas these solutions were not imbibed by dry Sand 1. The imbibition mechanism in this case is believed to be gravitational segregation of liquids in the pore spaces of sand due to decreased capillary pressure.

Saponification of naturally occurring petroleum acids in the Varsol-crude mixture with the alkaline solutions results in the reduction of water-oil interfacial tension and consequently reduced the capillary pressure in the pore spaces. Gravitational pressure difference between oil and water overcome this reduced capillary pressure. Therefore, water is imbibed by the sand. However, thin films of oil were observed on the sand surfaces. This indicates that the sand is still oil wet. In the dry sand, no saponification is taking place since the dry sand does not contain petroleum acids. Therefore, no imbibition of water into the dry sand occurs.

Cooke et al (103) also observed vertical oil migration in oil wet systems with gravity as the driving force, and stated that low interfacial tension seems to be impor-

tant for this drainage mechanism.

Some chemicals such as Triton X-100, Na_4EDTA, Na-oleate and Sample G were imbibed by both the dry sand and the sand saturated with the Varsol-crude mixture. These chemicals except Triton X-100 contain carboxylate anions, which reduced the interfacial tension and gave rise to gravitational segregation of liquids. Triton X-100 is a nonionic surfactant whose major component is polyoxyethlene alkyl phenol. Triton X-100 was spontaneously imbibed by all sands regardless of initial saturation condition. The imbibition mechanism in this case is different from that described above, and is regarded as wettability reversal from oil wet to water wet due to either chemical or physical adsorption to sand grains.

Cell Imbibition Test Results

A summary of cell imbibition test data is presented in Table B - 2 in Appendix B.

As would be expected from the bench tests, little imbibition of brine by Sand 2 saturated with the Varsol-crude mixture was observed. No imbibition of brine into Sand 1 saturated with the Varsol-crude mixture was consitent with the result of bench test, which indicated oil wet characteristics of the Sparky sand.

One percent sodium hydroxide in brine solution was readily imbibed by the Ottawa sand saturated with the Varsol

-crude mixture and produced 56% pore volume of oil from the Ottawa sand, while it produced only 12% pore volume of oil from Sparky sand. This indicates that, at the same interfacial tension condition, more oil was produced from the water wet Ottawa sand than the oil wet Sparky sand.

Chemicals such as Na-oleate, Na_4EDTA, NaOH and Sample G were readily imbibed by Sparky sand saturated with the Varsol-crude mixture. The imbibition mechanism involved in this case is regarded as gravitational segregation of fluids resulted from low capillary pressure. This mechanism is characterized by low oil recovery compared to that by the wettability reversal mechanism. One percent Triton X-100 in brine solution produced 71% pore volume of oil and the recovery mechanism involved in this case is believed to be wettability reversal of the Sparky sand from oil wet to water wet. Vertical movement of the stabilized water-oil front was observed while 1% Triton X-100 solution displaced the oil from Sparky sand core.

Samples B, E and G were readily imbibed by Sparky sand saturated with Varsol-crude mixture. However, there was no indication of wettability change of the sand.

The study of molecular structure of the sand materials may be helpful in understanding its wettability characteristics. The structure of quartz, which is a major component of the sand, is comprised of three dimensional SiO_4^{4-} tetrahedra, in which the central Si atom is hydbrid-

ized, sp^3, and forms σ-bonds with four oxygen atoms (104). A large number of brocken bonds may appear on the surface of quartz upon fracturing of the Si-O bonds. These brocken bonds at the surface may react with water to form surface silicic acids (105). If a crude oil has basic components such as pyridine and quinoline, these basic components probably react with the silicic acid surface of the quartz resulting in the adsorption of the crude oil to the sand surfaces; thus adsorption renders the sand oil wet.

The increase in carboxylic acid adsorption on a quartz surface in the acidic range of pH, however, is not due to its polar attraction with quartz but rather to the low solubility of the carboxylic acid in molecular form (106). Due to the hydrophobic property, carboxylic acid would be squeesed out from water and concentrate at water quartz interface even if there is no special attraction between quartz and carboxylic acid. Upon reaction with a base, the acid previously adsorbed on the quartz surface in molecular form would be ionized and dissolved in water. This could be one of the reasons why water-wet Ottawa sand, in contact with the crude, became slightly oil wet but reversed to water wet on reaction with sodium hydroxide.

The results of the bench and cell imbibition tests indicated that the Lloydminster crude oil contains certain organic components which have special affinity for sand surfaces. Since these components did not react with sodium

hydroxide solution, they are considered as non acidic materials and may be related to resins and asphaltines.

Interfacial Tension Results

The effect of various chemicals on interfacial tension was measured for a number of aqueous solutions and oils. The results of the tests are presented in Tables B - 3, to B - 17 in Appendix B.

The effect of sodium hydroxide concentration on interfacial tension is shown in Figure 6. The interfacial tension between Varsol and distilled water was not significantly affected by NaOH concentrations. Varsol exhibits relatively neutral interfacial properties and is believed to contain no potential surfactants. Because of this neutrality, Varsol was used as hydrocarbon solvent to decrease the viscosity effect of crude oil in the imbibition tests.

The interfacial tension between the Lloydminster crude and distilled water was decreased to an immeasureably low value, less than 0.4 dynes/cm, at a sodium hydroxide concentration of 0.04% by weight. A similar low value of interfacial tension between the Lloydminster crude and brine was obtained at a sodium hydroxide concentration of 0.004% by weight. Since sodium chloride was the only chemical added to the brine, the significant difference in sodium hydroxide concentration required to reach the same interfacial

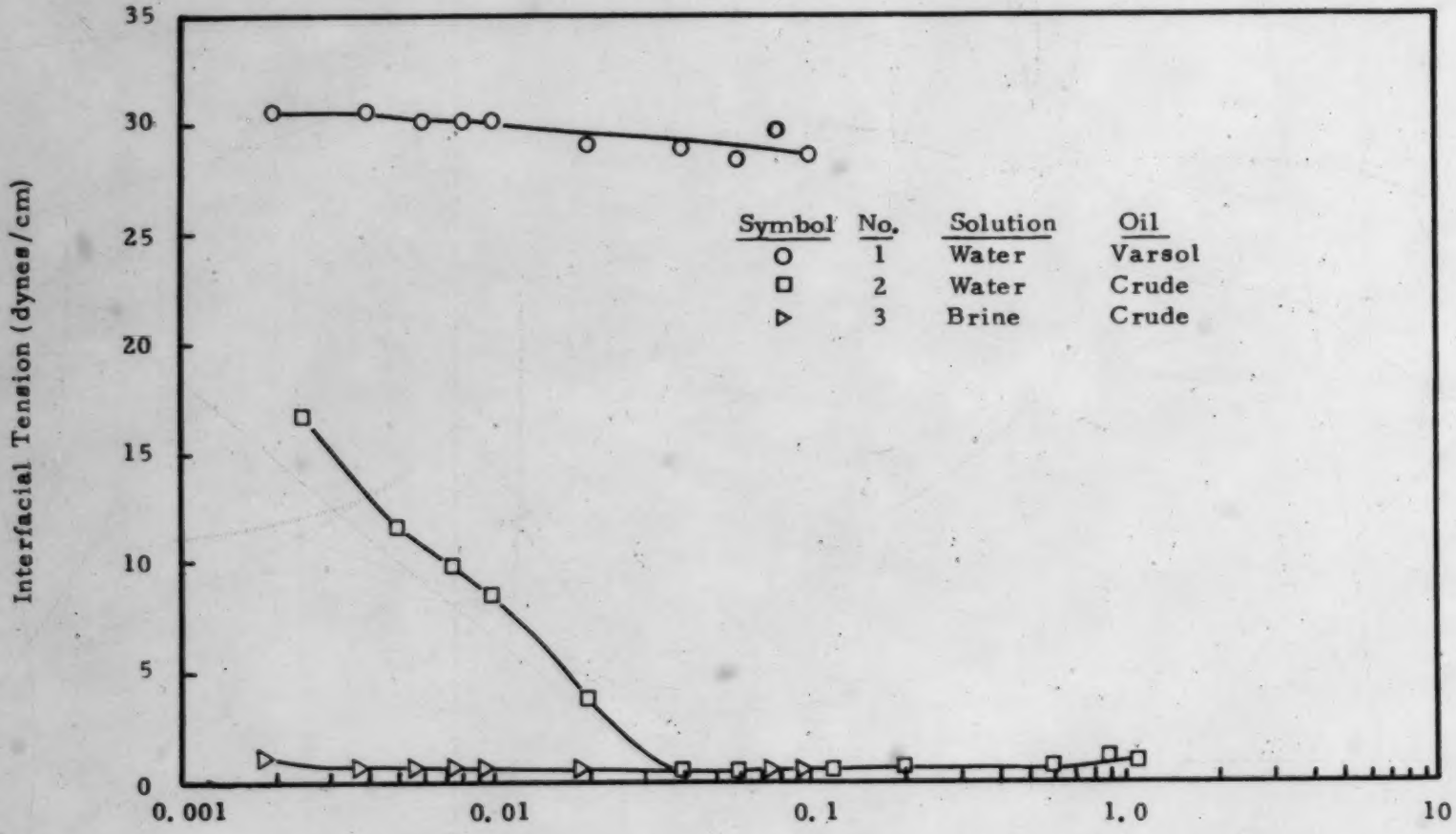


FIG. 6 - INFLUENCE OF NaOH CONCENTRATION ON INTERFACIAL TENSION

tension can be attributed to the effect of sodium chloride. Sodium chloride, in combination with sodium hydroxide, accelerates the interfacial tension reduction. This resulted in a reduction of the amounts of sodium hydroxide required to achieve a given level of interfacial tension.

Figure 7 shows the relationship between sodium hydroxide concentration and the pH of solutions. The pH of solutions increased readily as the sodium hydroxide concentration increased. The pH of brine is slightly less than that of distilled water at the same sodium hydroxide concentration.

Figure 8 shows that the pH has a marked effect on interfacial tension. It may be observed that at a low pH value, all the systems exhibit relatively constant interfacial tensions. But as the pH increases beyond some critical value, the interfacial tensions fall sharply. The critical pH values are 11, 8.5, and 11.2 for the water-crude, brine-crude and brine-oleic acid systems, respectively. It may also be observed that the water-Varsol system shows no significant change in the interfacial tension throughout the range of pH studied.

Carboxylic acids are believed to be responsible for the interfacial tension reduction observed above. Carboxylic acids react with sodium hydroxide to form soaps, which ionize in the water phase depending upon the pH of the solution. Carboxylate anions so formed concentrate at the water-oil interface. The arrangement of carboxylate anions

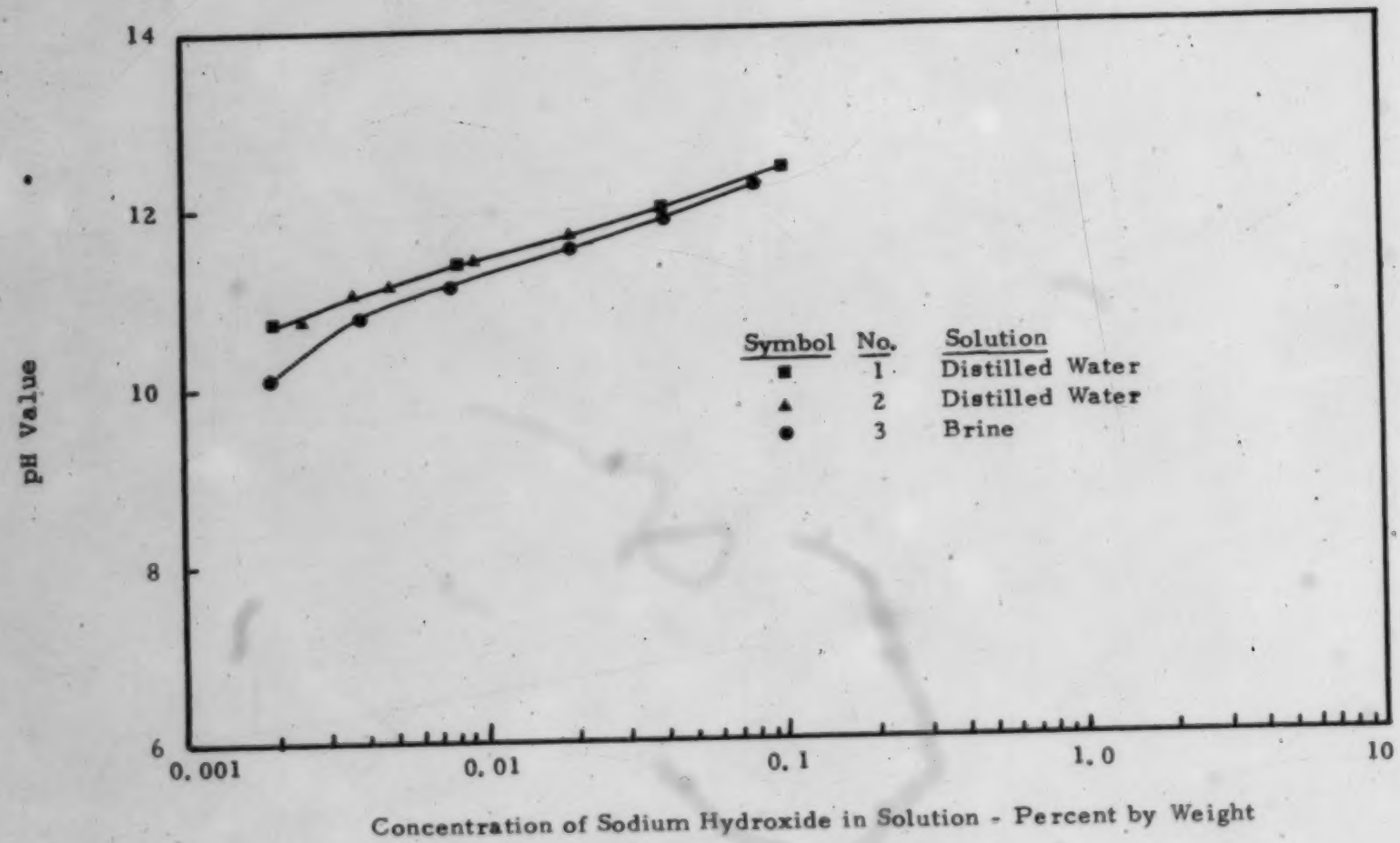


FIG. 7 - INFLUENCE OF NaOH CONCENTRATION ON THE pH OF VARIOUS SOLUTIONS

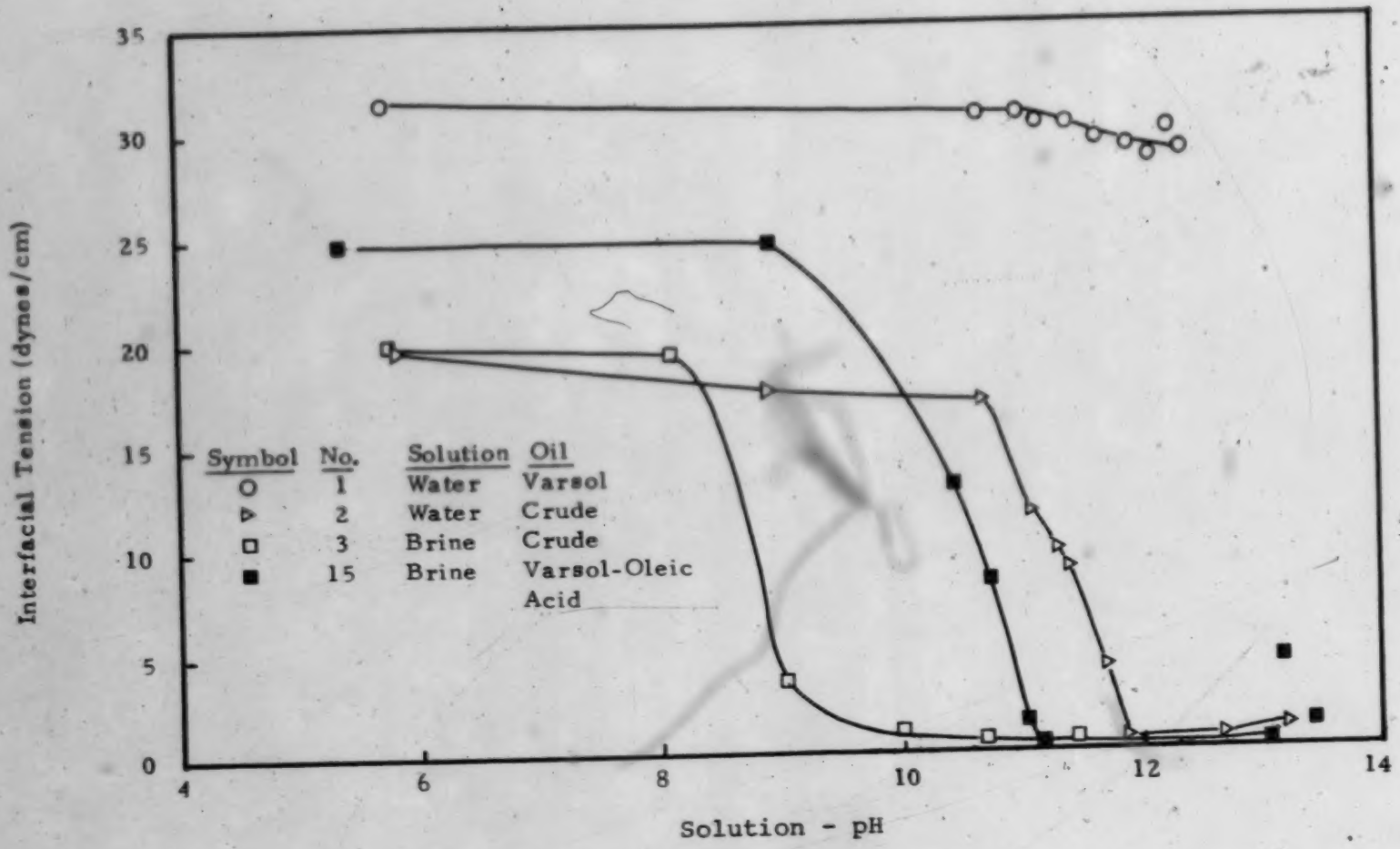


FIG. 8 - RELATIONSHIP OF AQUEOUS SOLUTION pH AND INTERFACIAL TENSION

and their counter ions, Na^+, at the water-oil interface results in the interfacial tension reduction. On the other hand, the absence of carboxylic acids in the water-Varsol system is accountable for little change in the interfacial tension.

The brine-oleic acid system showed white turbidity at the water-oil interface at a pH of 11.2. At a pH of 13.2, a rigid film formed at the interface was observed. The spontaneous emulsification is believed to be responsible for the turbidity.

The interfacial tensions between crude and various chemical solutions are shown in Figure 9. For the sodium oleate-crude system, interfacial tension was reduced to essentially zero at a concentration of 0.05%. Triton X-100 did not reduce the water-oil interfacial tension below 0.7 dynes/cm even at the high concentration of 3.4%. Interfacial tension at a concentration of 1% is 3.5 dynes/cm, which is rather high to cause an increase in oil recovery. Therefore, the high oil recovery from cell imbibition test with 1% Triton X-100 can be attributed to wettability reversal mechanism.

Figure 10 shows the effect of chemical concentrations on interfacial tension. Samples B and G appear to be the most efficient in reducing interfacial tension. For both of them, the interfacial tension becomes essentially zero at a concentrations of 0.5%, while Sample E reduced the

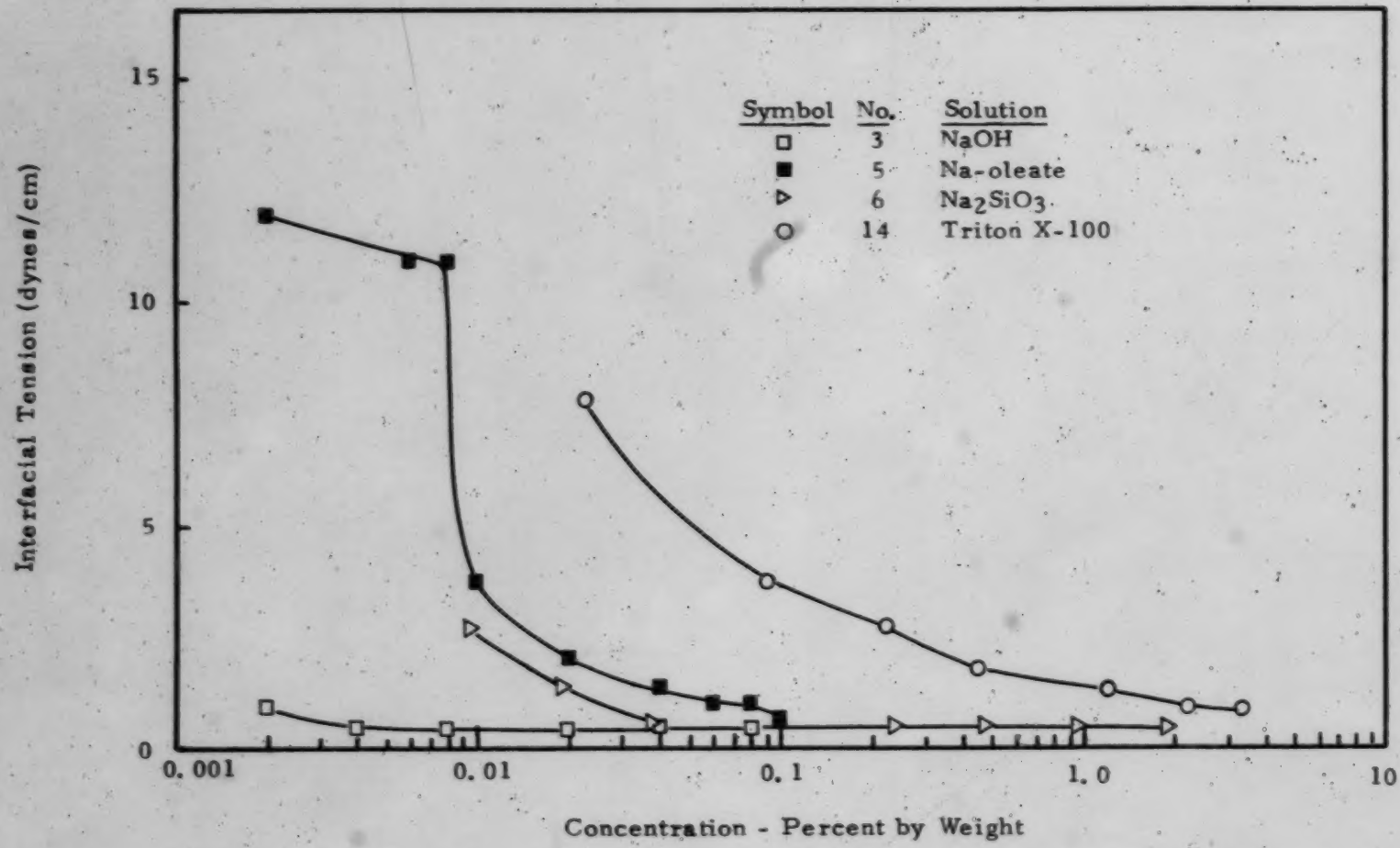


FIG. 9 - EFFECT OF CHEMICAL CONCENTRATIONS ON INTERFACIAL TENSION

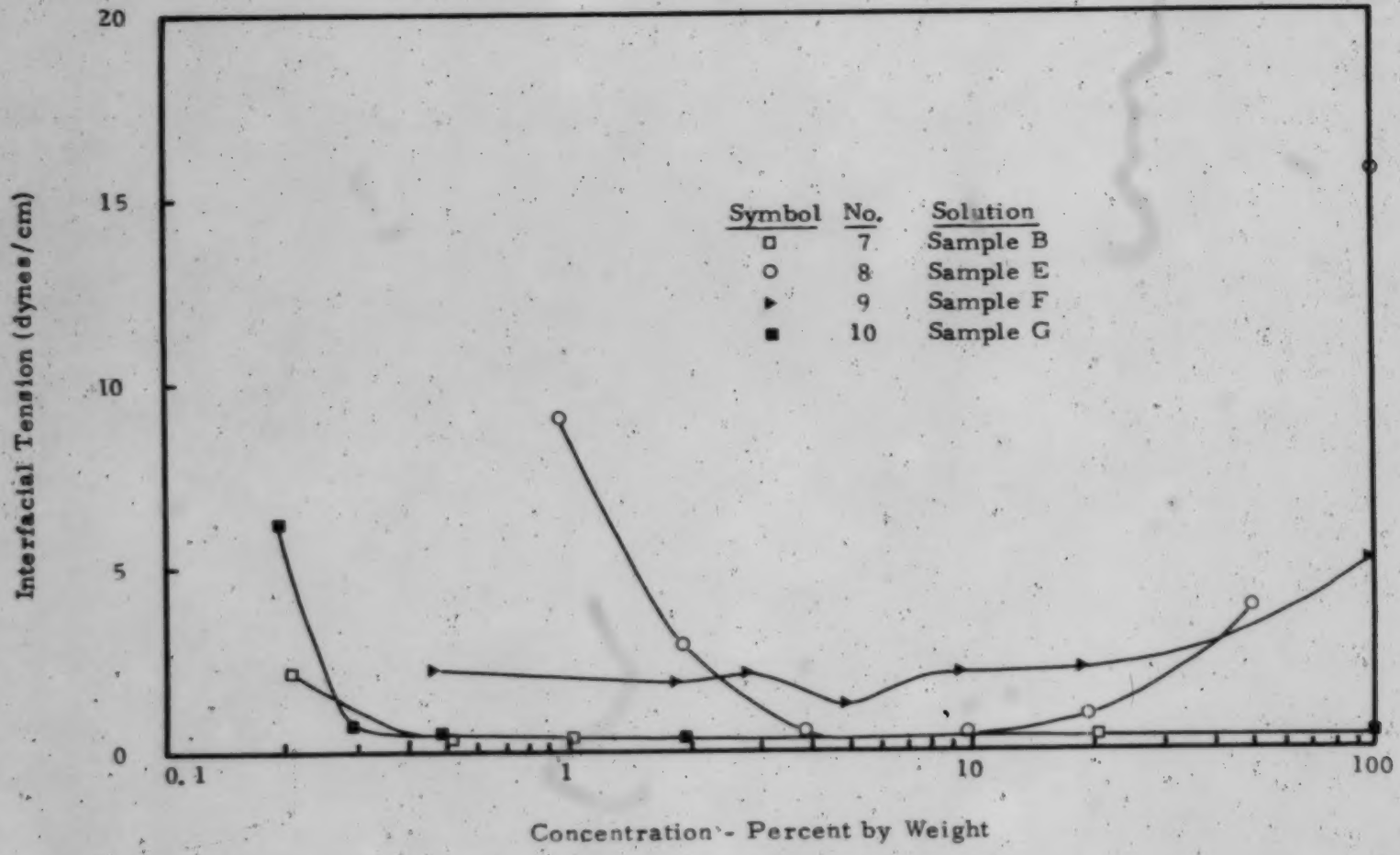


FIG. 10 - EFFECT OF SAMPLE CONCENTRATIONS ON INTERFACIAL TENSION

interfacial tension to a similar value at a concentration of 4%. With the exception of Sample G, all other sample solutions show a tendency to increase interfacial tension at relatively high concentrations. Sample B begins to increase the interfacial tension beyond a concentration of 20%, while the interfacial tension increases beyond a concentration of 10% for Sample E-crude system. The interfacial tension in Sample F-crude system was not reduced to a value less than 1.2 dynes/cm throughout the concentration range of the study.

Figure 11 shows the relationship between Sample pH and interfacial tension. Sample B, E and G exhibit essentially zero interfacial tension at the same pH value of 9.5. Samples B and E show the above mentioned tendency of increasing interfacial tension at the pH value of 11.7 and 10.2 respectively. No indication of the increase in the interfacial tension was, however, observed for Sample G. This exhibits a rather wide range of concentration over which interfacial tension is essentially zero.

Figure 12 shows the relationship between the interfacial tension and Sample G concentration in various aqueous solutions. The interfacial tension between Varsol and Sample G in distilled water is decreased readily as the Sample G concentration increases. This implies that surface active materials in Sample G are responsible for the interfacial tension reduction since Varsol contains no surfactant.

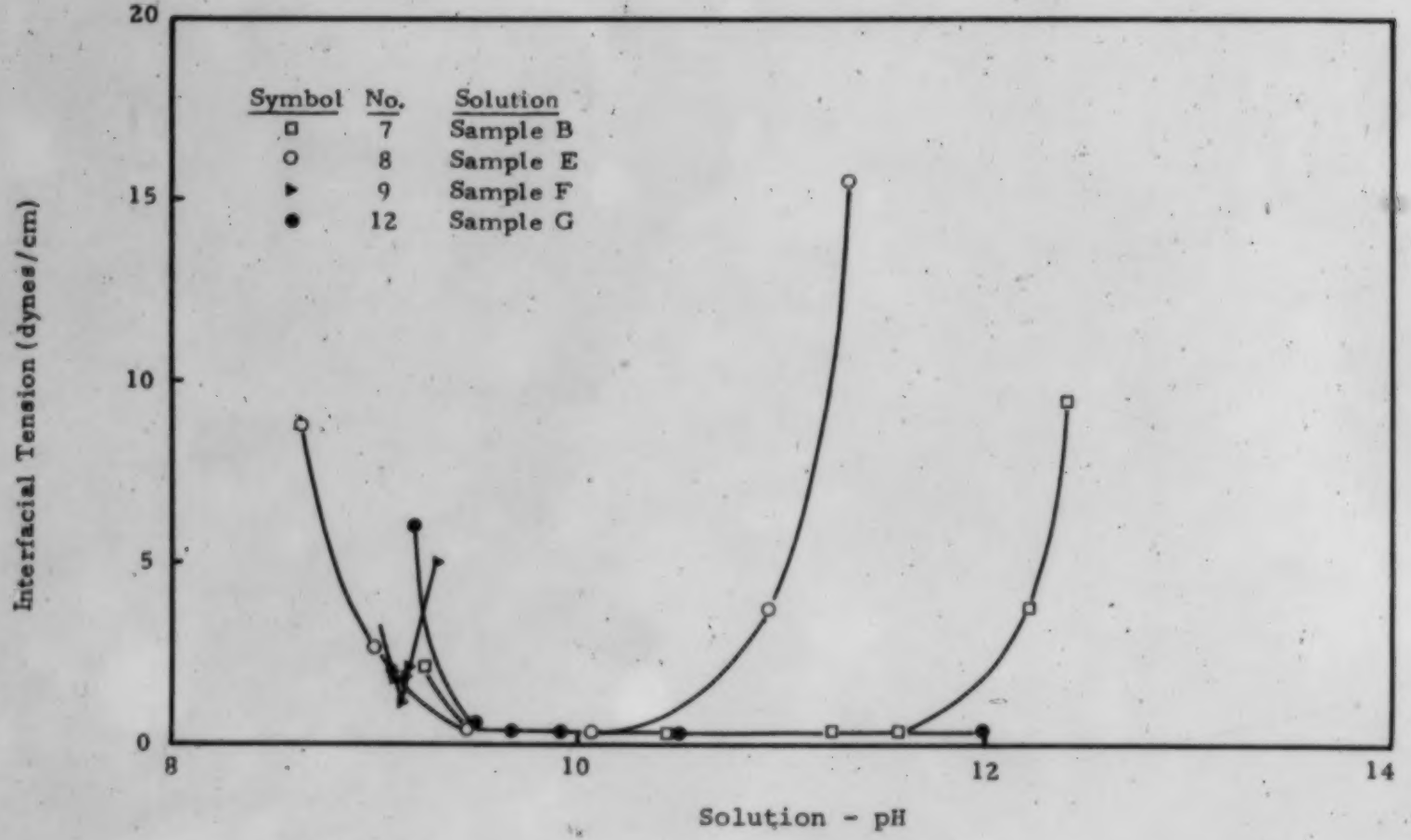


FIG. 11 - RELATIONSHIP OF SAMPLE pH AND INTERFACIAL TENSION

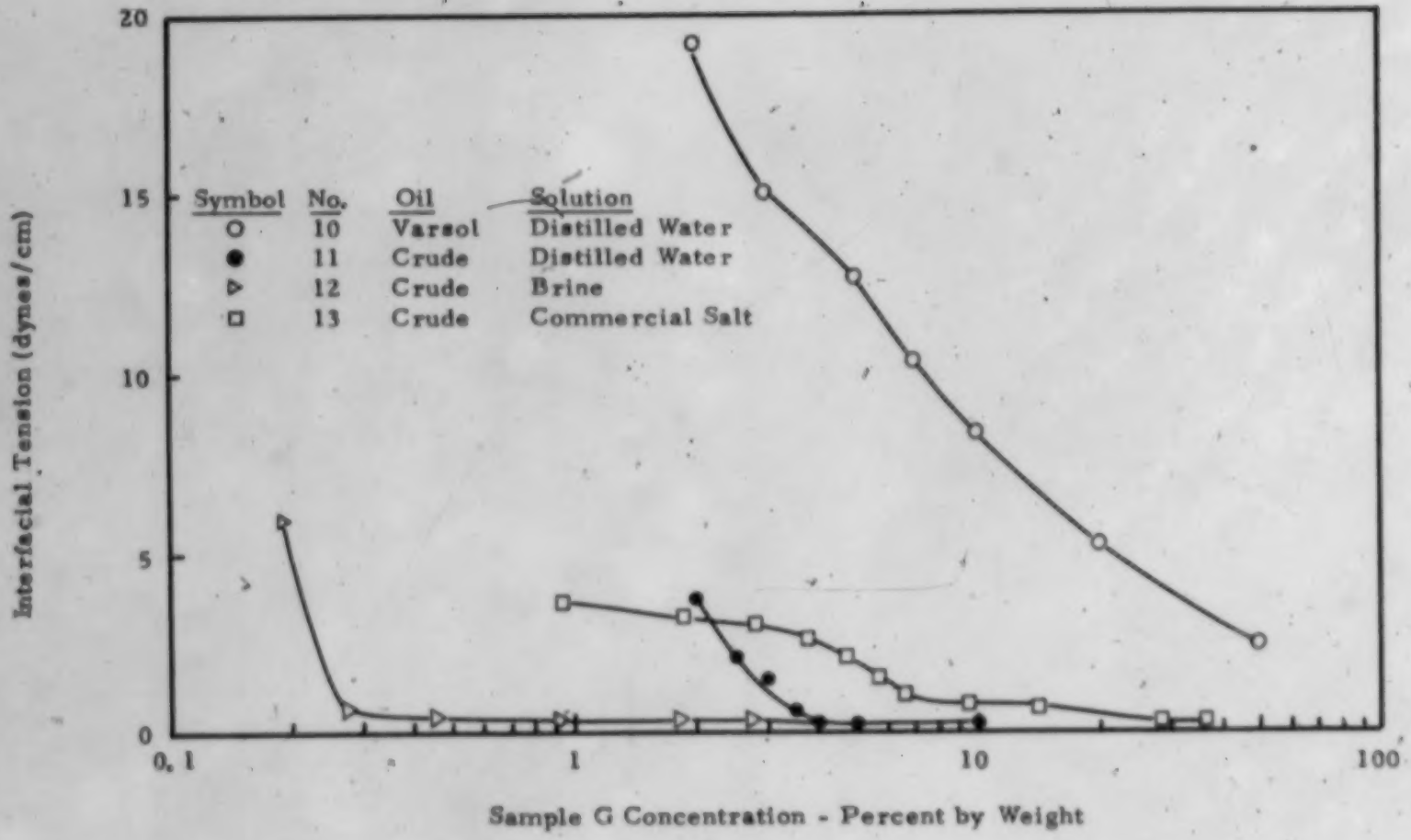


FIG. 12 - EFFECT OF SAMPLE G IN VARIOUS SOLUTIONS ON INTERFACIAL TENSION

The interfacial tension between crude and Sample G in brine is reduced to less than 0.4 dynes/cm at a concentration of 0.5%, while Sample G in distilled water exhibits the similar interfacial tension at a concentration of 4%. This difference in Sample G concentration required to obtain the similar interfacial tension is attributable to the effect of the inorganic salt, NaCl. The interfacial tension between crude and Sample G in commercial salt solution, was not reduced below 0.8 dynes/cm until the Sample G concentration raised to approximately 15%. At a concentration of 30%, the interfacial tension is reduced to essentially zero. The delayed interfacial tension reduction for Sample G in commercial salt solution is attributed to the effect of impurities in commercial salt. Divalent cations such as Ca^{++} and Mg^{++} produce insoluble compounds, $Ca(OH)_2$ and $Mg(OH)_2$ on reaction with NaOH solution. These cations also react with carboxylate anions and precipitate in the forms of $(RCOO)_2Ca$ and $(RCOO)_2Mg$ since the solubility of these salts is extremly low. Therefore, impurities consume certain amounts of both NaOH and Carboxylate ions required to reduce interfacial tension. Similar phenomena have been observed by many investigators (107, 108, 109, 110). Among the impurities occurring in natural formation water, the calcium ion showed the most adverse effect on the interfacial tension reduction.

Samples B, E and G appear to be promising in reducing interfacial tension at relatively low concentrations. These samples have not only a high pH value but also contain carboxylate ions (see Fig. 13). For these Sample-crude systems, the interfacial tensions fell to essentially zero at a pH of 9.5, whereas sodium hydroxide-crude system required the pH to be at least 10.5. The low pH of the sample solutions required to obtain similar reductions in interfacial tension is attributable to the presence of carboxylate anions. Cooke et al (111) reported that the minimum acid number of crude oil required in successful alkaline flooding is in the range of 1.5. The acid number is defined as the weight in milligrams of potassium hydroxide required to neutralize one gram of the oil. Therefore, if the natural acids content of a certain crude is low, the required level of acids content necessary for enhanced recovery may still be achieved by the introduction of these sample solutions.

Effect of Inorganic Salt on Interfacial Tension

During the interfacial tension tests, it was observed that the presence of salt, NaCl, in the surfactant solutions accelerated the reduction of interfacial tension. A theoretical explanation for this phenomenon was attempted utilizing Gibb's adsorption equation.

Consider the system of oil-water which contains surfactant such as a sodium salt of carboxylic acid, RCOONa/

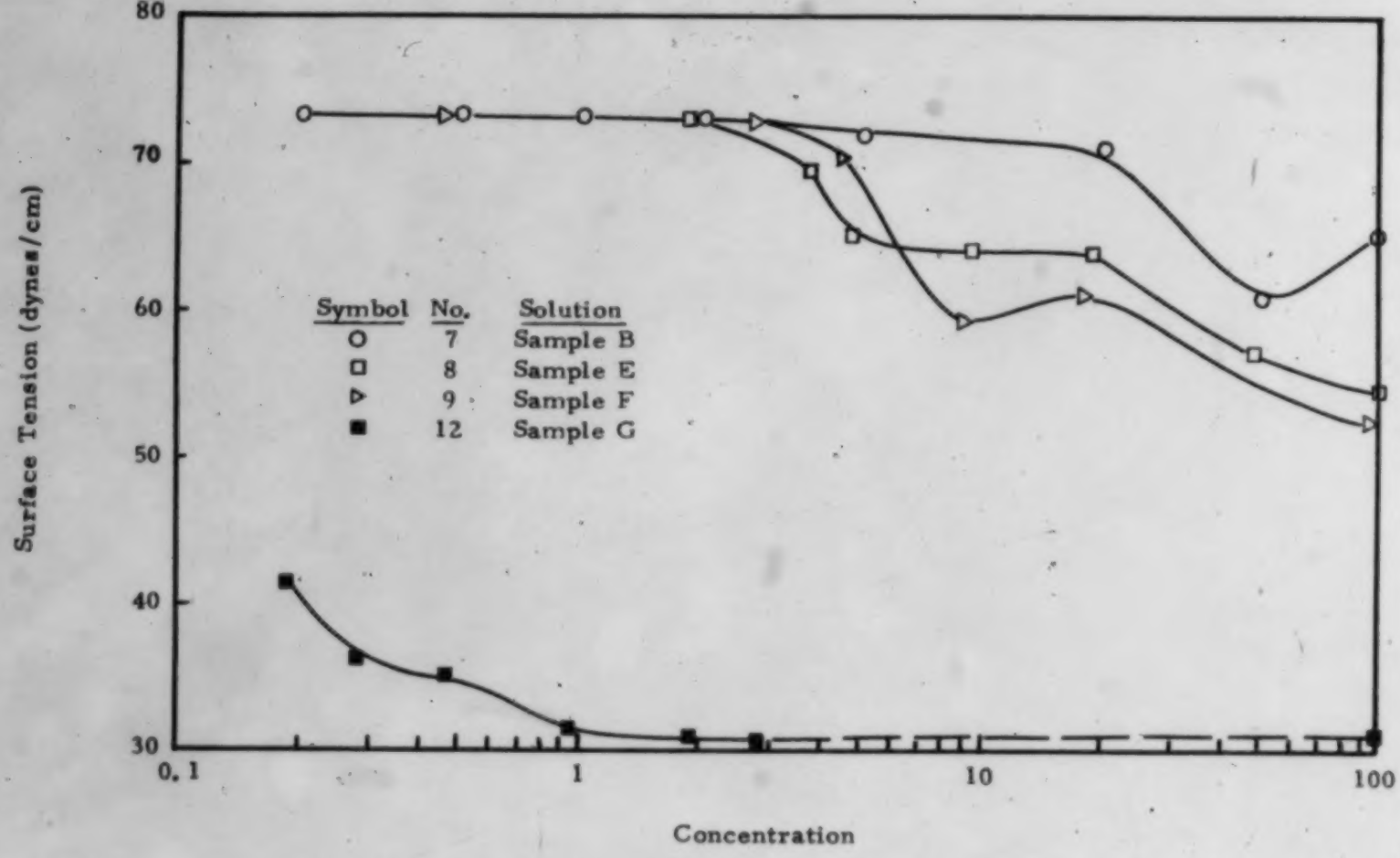


FIG. 13 - EFFECT OF SAMPLE CONCENTRATIONS ON SURFACE TENSION

together with a neutral inorganic salt, NaCl. This surfactant will be positively adsorbed at the water-oil interface. The Gibb's adsorption equation for this system may be written as follows

$$d\gamma = - \Gamma_{Na+} d\mu_{Na+} - \Gamma_{Cl-} d\mu_{Cl-} - \Gamma_{RCOO-} d\mu_{RCOO-} \qquad 6$$

This relation may be simplified by introducing the chemical potential of the salt,

$$\mu_{NaCl} = \mu_{Na+} + \mu_{Cl-}$$

$$\mu_{RCOONa} = \mu_{Na+} + \mu_{RCOO-}$$

and the condition for electroneutrality at the interface

$$\Gamma_{Na+} = \Gamma_{RCOO-} + \Gamma_{Cl-}$$

Equation 6 becomes

$$d\gamma = - \Gamma_{RCOO-} d\mu_{RCOONa} - \Gamma_{Cl-} d\mu_{NaCl}$$

At constant pressure and temperature the chemical potential of species i in an aqueous solution is determined by the relation

$$\mu_i = \mu_i^\circ + RT \ln a_i = \mu_i^\circ + RT \ln \lambda_i C_i$$

where λ_i is the activity coefficient and C_i the molar concentration of species i.

Since it is very difficult, if not impossible, to measure individual ionic activity we may introduce the mean

ionic activity which is measurable. The mean ionic activity is the geometric mean of the individual ion activities;

$$a_{\pm}^{\nu} = a_{+}^{\nu^+} a_{-}^{\nu^-} \qquad (\nu = \nu^+ + \nu^-)$$

$$a = a_{\pm}^{\nu}$$

where the quantities, ν^+ and ν^- refer to the number of cations and anions respectively. For uni-univalent electrolytes, the various activity coefficients are defined by the relations

$$a_{\pm} = \lambda_{\pm} C$$

$$\lambda_{\pm}^2 = \lambda_{+}\lambda_{-}$$

$$C_{\pm}^2 = C_{+}C_{-}$$

where $\lambda_{\pm}$ and $C_{\pm}$ are the mean ionic activity coefficient and mean ionic concentration respectively.

Hence, the chemical potential of RCOONa and NaCl can be expressed as follows.

$$\mu_{RCOONa} = \mu^{0}_{RCOONa} + RT\ell n\left[\lambda^2_{\pm(Na+,\ RCOO-)} C_{Na+} C_{RCOO-}\right]$$

$$\mu_{NaCl} = \mu^{0}_{NaCl} + RT\ell n\left[\lambda^2_{\pm(Na+,\ Cl-)} C_{Na+} C_{Cl-}\right]$$

using these relations, equation 7 becomes

$$d\gamma = -\Gamma_{RCOO-} RT\left[d\ell nC_{Na+} + d\ell nC_{RCOO-} + d\ell n\lambda^2_{\pm(Na+,RCOO-)}\right]$$
$$- \Gamma_{Cl-} RT\left[d\ell nC_{Na+} + d\ell nC_{Cl-} + d\ell n\lambda^2_{\pm(Na+,Cl-)}\right]$$

In rearrangement, this equation becomes

$$d\gamma = - RT\left[\Gamma_{RCOO^-} d\ell n C_{RCOO^-} + \Gamma_{Cl^-} d\ell n C_{Cl^-} + \Gamma_{Na^+} d\ell n C_{Na^+}\right.$$

$$\left. + 2\Gamma_{RCOO^-} d\ell n \lambda^2_{\pm(Na^+,RCOO^-)} + 2\Gamma_{Cl^-} d\ell n \lambda^2_{\pm(Na^+,Cl^-)}\right] \quad 8$$

If the ionic strength of the solution is dominated by the concentrations of NaCl ($C_{NaCl} >> C_{RCOONa}$), then at constant ionic strength the equation 8 is simplified to

$$d\gamma = - RT\, \Gamma_{RCOO^-} d\ell n C_{RCOO^-}$$

This equation implies that interfacial tension is decreased as the concentration of carboxylate anion, $RCOO^-$ is increased. In other words, the presence of organic electrolyte in an aqueous solution decreases the interfacial tension.

If the ionic strength of the solution is now increased by increasing the concentration of NaCl while keeping RCOONa concentration constant, equation 8 becomes

$$d\gamma = - RT\Gamma_{RCOO^-}\left[d\ell n C_{Na^+} + d\ell n \lambda^2_{\pm(Na^+,RCOO^-)}\right] \quad 9$$

In arriving at this relationship, we assumed an adsorption density for chloride ion is negligible because NaCl will be negatively adsorbed in the absence of organic electrolyte and the chloride ion will be repelled from the interface in the presence of the positively adsorbed organic anion, $RCOO^-$ due to electrostatic repulsion between the

charges of the same sign. The Cl^- ion is an indifferent ion which has no special affinity for an interface.

Now we may introduce the Debye-Huckel limiting law for univalent ions in water solution.

$$\ell n \lambda_{\pm}^2 = - 2.303 \, U^{\frac{1}{2}}$$

where U is the ionic strength of a solution. The ionic strength for uni-valent ions is defined by

$$U = \frac{1}{2} \Sigma C_i$$

where the sum is over all the different kinds of ions in the solution.

The Debye-Huckel limiting law predicts that the logarithm of mean ionic activity coefficient should be a linear function of the root of ionic strength (112). However, the approximations required in the theory restrict its validity to solutions which are very dilute. In practice deviations from the limiting law become appreciable as the concentration increases. The change of mean ionic activity coefficient due to the change of concentration becomes negligible as the concentration increases. Therefore, the decrease in the quantity $\lambda^2_{\pm(Na+,RCOO-)}$ due to increasing ionic strength will certainly be less than the increase in Na^+ concentration;

$$d\ell n C_{Na+} >> d\ell n \lambda^2_{\pm(Na+,RCOO-)}$$

The term in the square brackets in equation 9 is, therefore,

positive and the derivative of the interfacial tension is negative. The negative dervative of interfacial tension indicates that the interfacial tension is decreased by increasing NaCl concentration at a constant RCOONa concentration.

The breaks in the interfacial tension reduction occur at cmc. Beyond this cmc, the interfacial tension does not decrease further with an increase in the electrolyte concentration (113, 114, 115). Further additions of either organic or inorganic electrolyte only increase the concentration of the micelles in the solution.

Displacement Test Results

Summaries of the displacement test results and the results of the individual tests are presented in Table C - 1 to C - 44 in Appendix C.

Scott (116) using the same displacement apparatus reported that initial core conditions could not be reproduced by resaturating flooded out cores. Similar results were obtained in the present work during preliminary tests. Therefore, all displacement tests were conducted using clean sand. He also found that the period of water and oil saturation might influence the recovery performance of the core. The periods of water and oil saturation in the present work were held constant. The core was saturated with brine and aged for about 5 hours, and flooded with oil to establish the initial water saturation and the initial oil in place.

The core saturated with oil was then allowed to stand overnight, approximately 16 hours.

A brine base flood defined the performance of each sand. All other chemical floods were compared to the base flood in order to evaluate the effectiveness of the chemicals on oil recovery.

In order to generalize the recovery performace, normalization of oil recovery was done by dividing cumulative volume of produced oil by volume of initial oil in place (IOIP). This permitted oil recoveries to be expressed in dimensionless form. Similarily, the volume of water injected was expressed in pore volume of core (PV).

Figure 14 shows oil recovery performace of brine floods. These floods exhibit a low oil recovery of 0.15 IOIP at water breakthrough. Oil recovery after breakthrough is significant. About 40% of original oil in place was recovered when 5 PV of water were injected. Upon further injection of water, no significant volume of oil was produced. The low breakthrough recovery and significant subordinate production are characteristics of brine floods.

Figure 15 shows the effect of sand wettability on oil recovery for brine floods. Ultimate recovery from water-wet Sand 2 is higher than that from oil-wet Sand 1 by 18%. Recovery performance of Sand 2 is similar to that of Sand 1 until water injected reaches 0.8 PV. Beyond this, the oil recovery from Sand 2 increases markedly until water injected

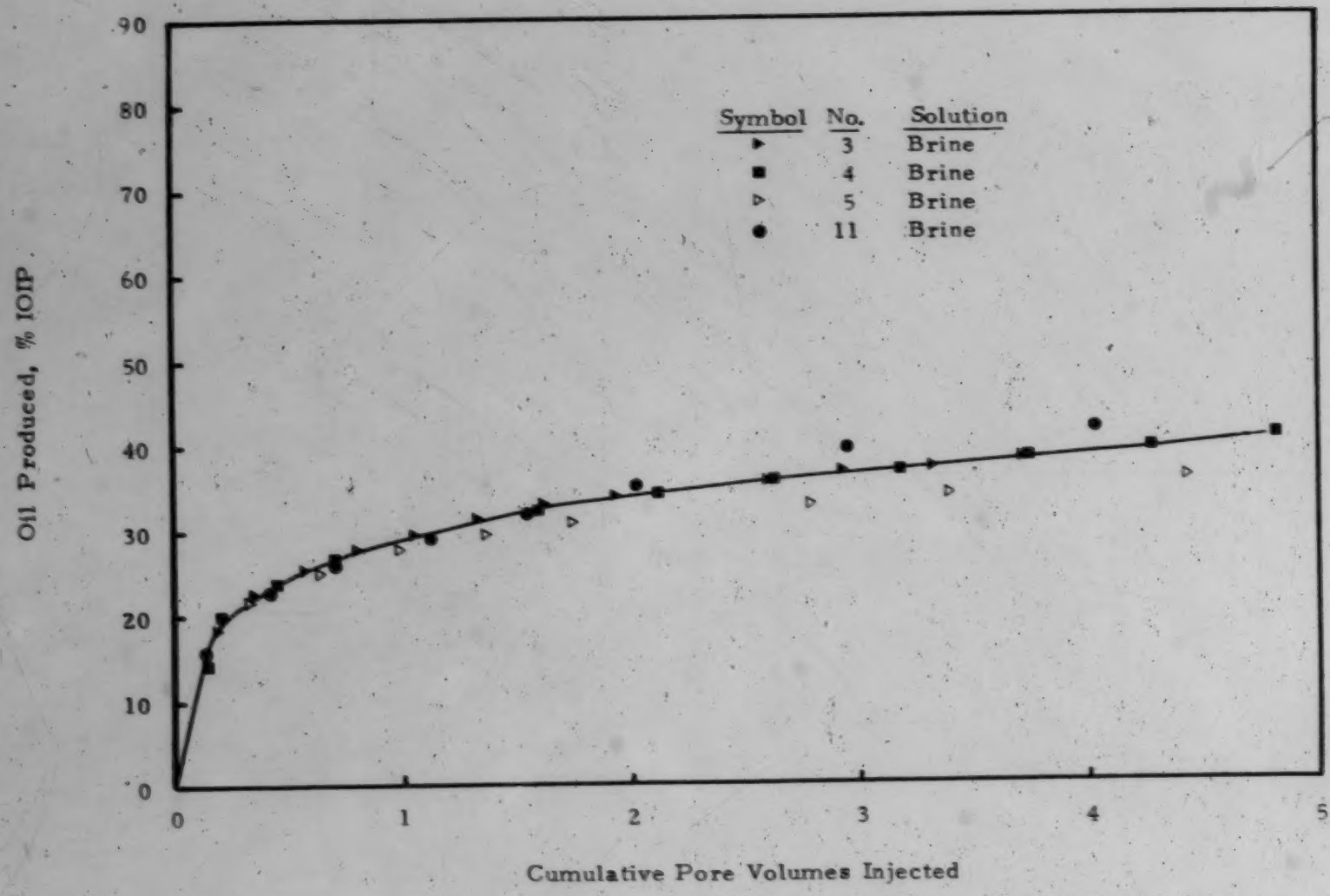


FIG. 14 - OIL RECOVERY FROM SAND 1 USING BRINE AS THE DISPLACING PHASE

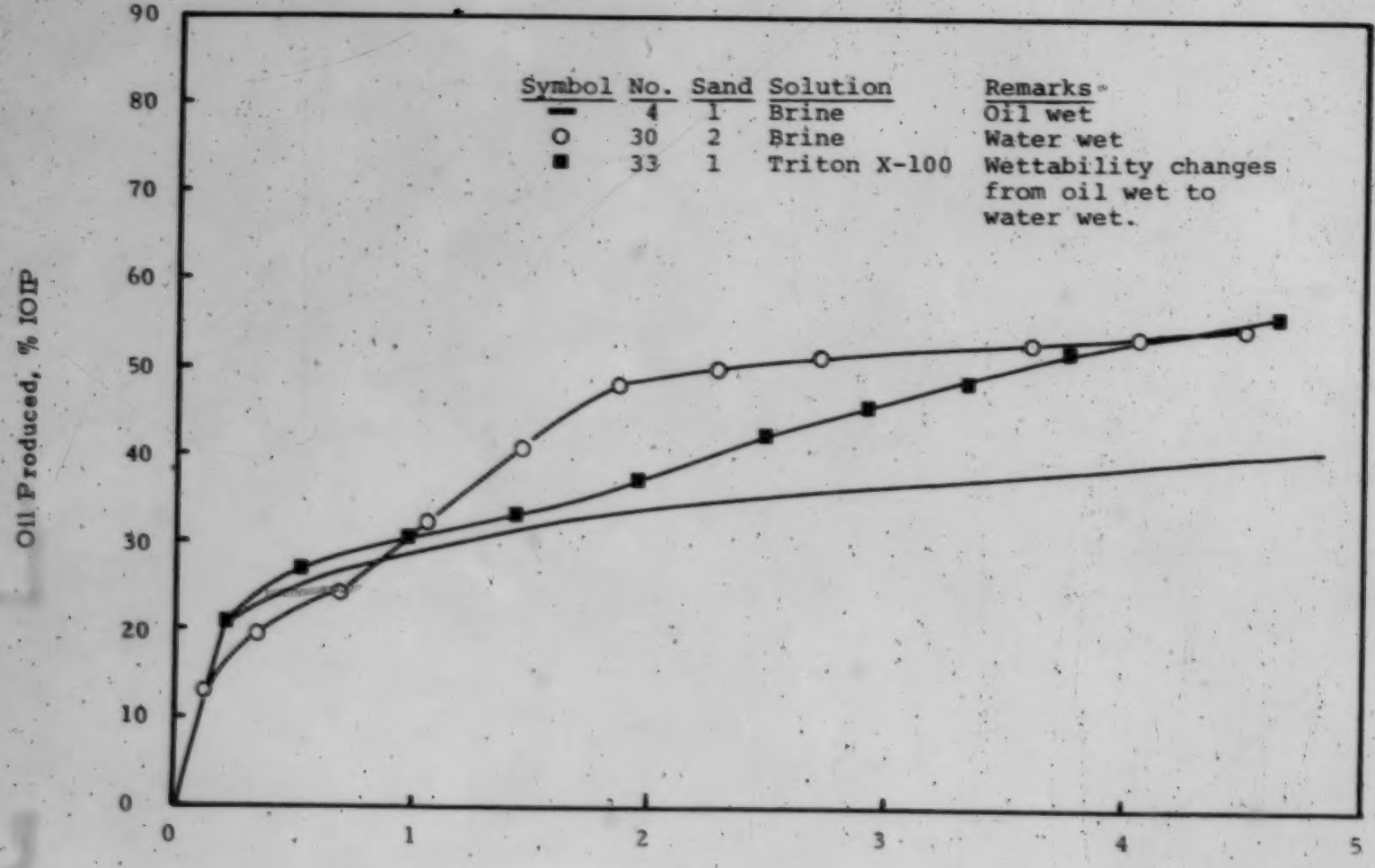


FIG. 15 - EFFECT OF WETTABILITY OF SAND ON OIL RECOVERY

reaches 1.8 PV, after which the rate of oil recovery is stabilized similar to that of Sand 1.

For 1% Triton X-100 in brine solution, no significant increase in oil recovery over that of a brine flood is noted until water injected reaches 1.6 PV. Beyond this point, oil recovery increases steadily. In order to reverse the wettability of Sand 1 from oil wet to water wet, Triton X-100 should penetrate the viscous crude oil layer which is highly immobile. Thus, no significant oil recovery is expected during the early stages of flooding. As the water displace the oil from sand surface, Triton X-100 would become more accessible to the sand surface and consequently change wettability of the sand resulting in a steady increase in oil recovery.

During the displacement tests, the pressure drop across the core was measured and recorded. The pressure drop ratio was calculated by dividing the pressure drop at a given cumulative pore volume of oil produced by the pressure drop at the beginning of water flood.

Figure 16 illustrates the relationship between volume of water injected and pressure drop ratio. The pressure drop ratio for brine floods in Sand 1 decreases monotonically with a sudden drop at the early stage of flooding history. On the other hand, the pressure drop ratio in water wet systems showed anomalies.

The pressure drop ratio anomalies in the range 1 -

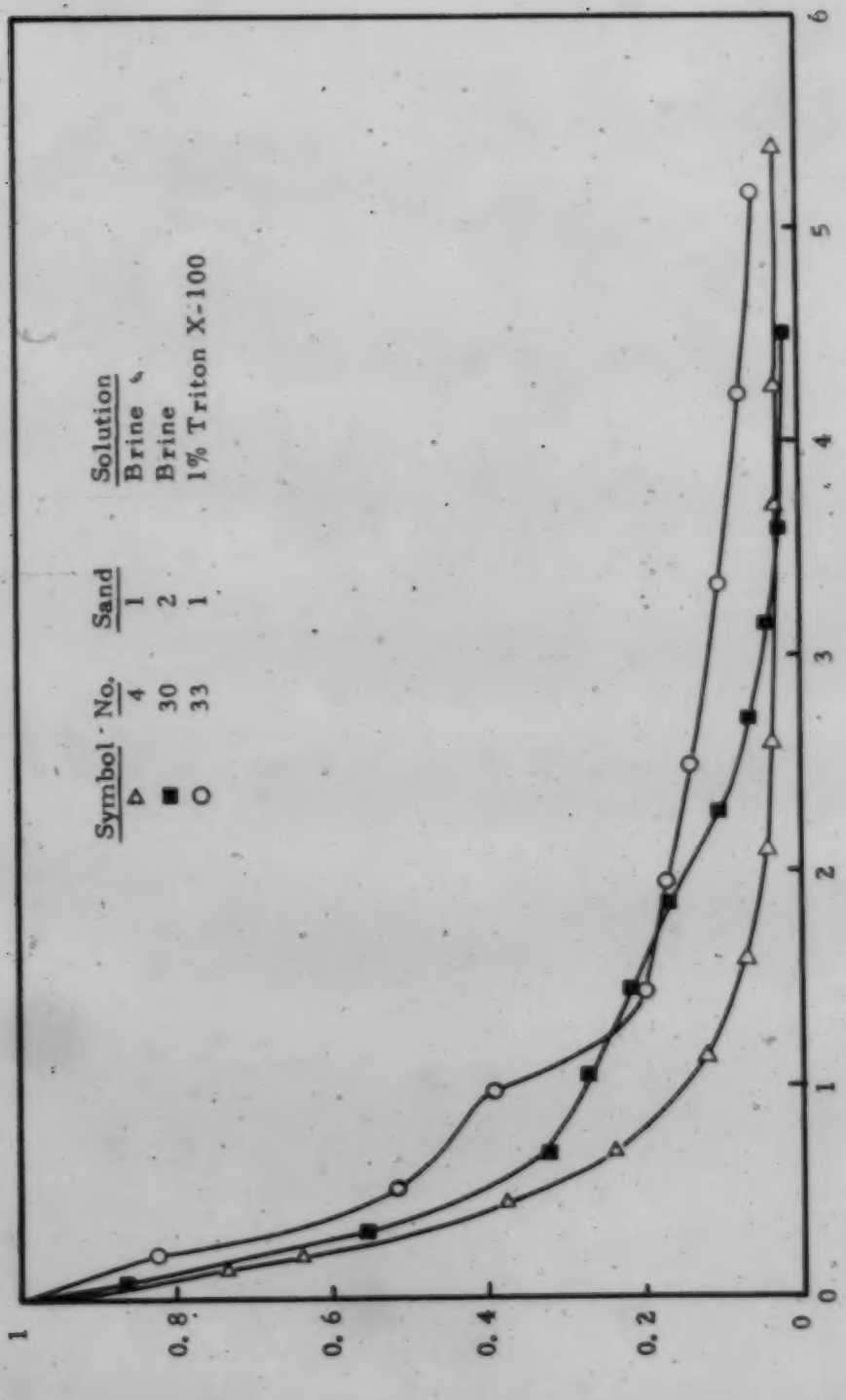


FIG. 16 - EFFECT OF WETTABILITY OF SAND ON PRESSURE BEHAVIOUR

2.3 PV water injected for 1% Triton X-100 flood in Sand 1 are well matched with the additional oil recoveries over that of a brine flood.

Displacement tests were conducted using a number of other chemicals in the injected brine. The results of these tests are illustrated in Figure 17. Three chemicals, Na_4-EDTA, sodium silicate and Sample G appear to be more effective than sodium hydroxide. Alconox appears to be somewhat less effective than sodium hydroxide. Among these chemicals Na_4EDTA shows the highest recovery characterized by high recovery after breakthrough which correlates well with the high pressure drop ratio at around 0.5 PV water injected (see Fig. 18).

Figure 19 shows the effect of various sample solutions on oil recovery and Figure 20 illustrates the corresponding pressure drop ratios. As would be expected, Samples G, E and B in that order are very effective in oil recovery. On the other hand, Sample F appears to be less effective than the brine flood.

Recalling that the pH of Sample F was not high enough to saponify the naturally occurring carboxylic acids in crude and that Sample F contained few carboxylate anions but large amounts of phenols which have been reported to have a diminishing effect on the interfacial activity, it is reasonable to expect that Sample F would have little effect on oil recovery. On the other hand, Samples G, E, and B have

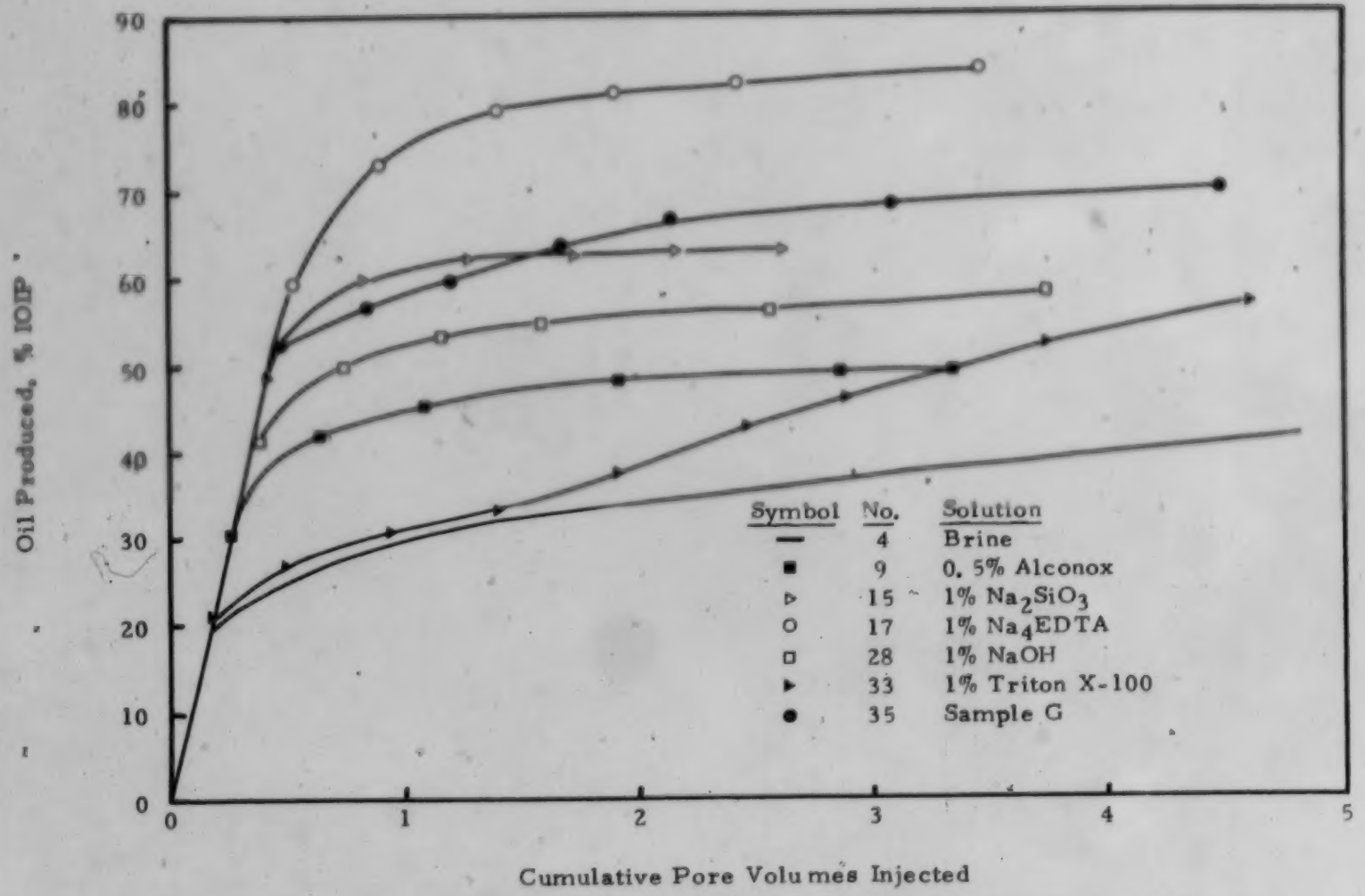


FIG. 17 - OIL RECOVERY FOR CHEMICAL IN BRINE DISPLACEMENT TESTS - SAND 1

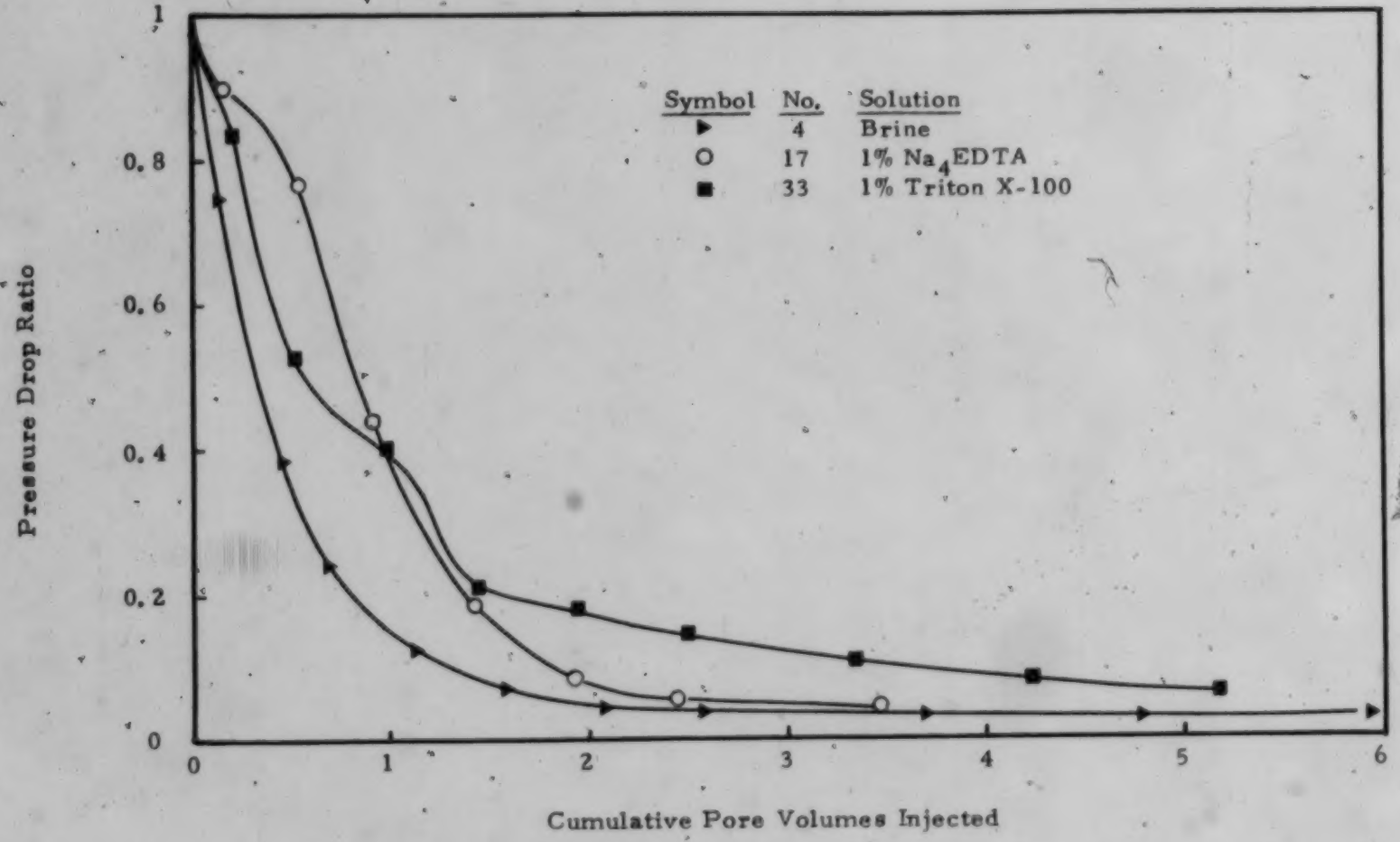


FIG. 18 - PRESSURE BEHAVIOUR FOR CHEMICAL DISPLACEMENT TESTS - SAND 1

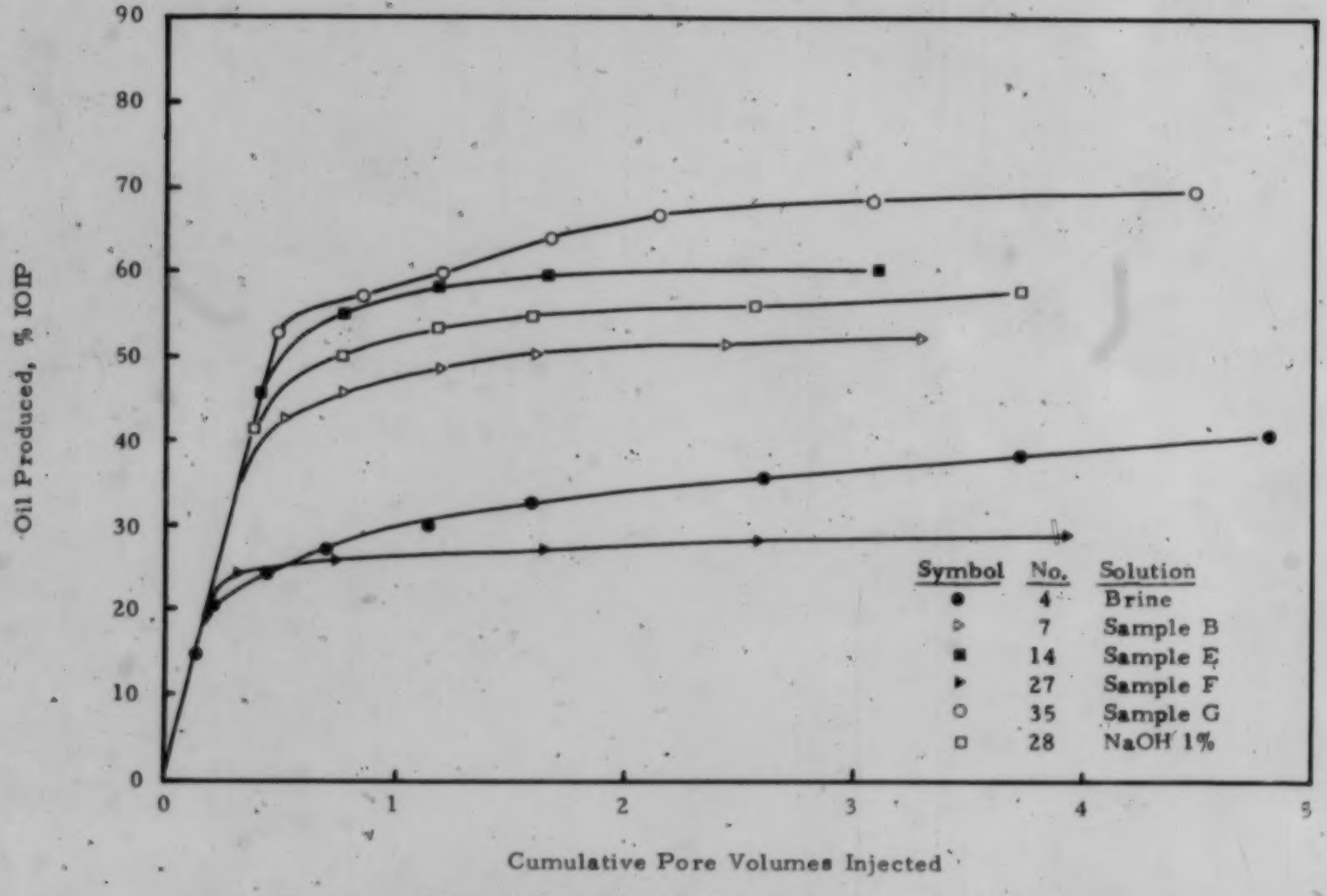


FIG. 19 - EFFECT OF VARIOUS SAMPLES ON OIL RECOVERY - SAND 1

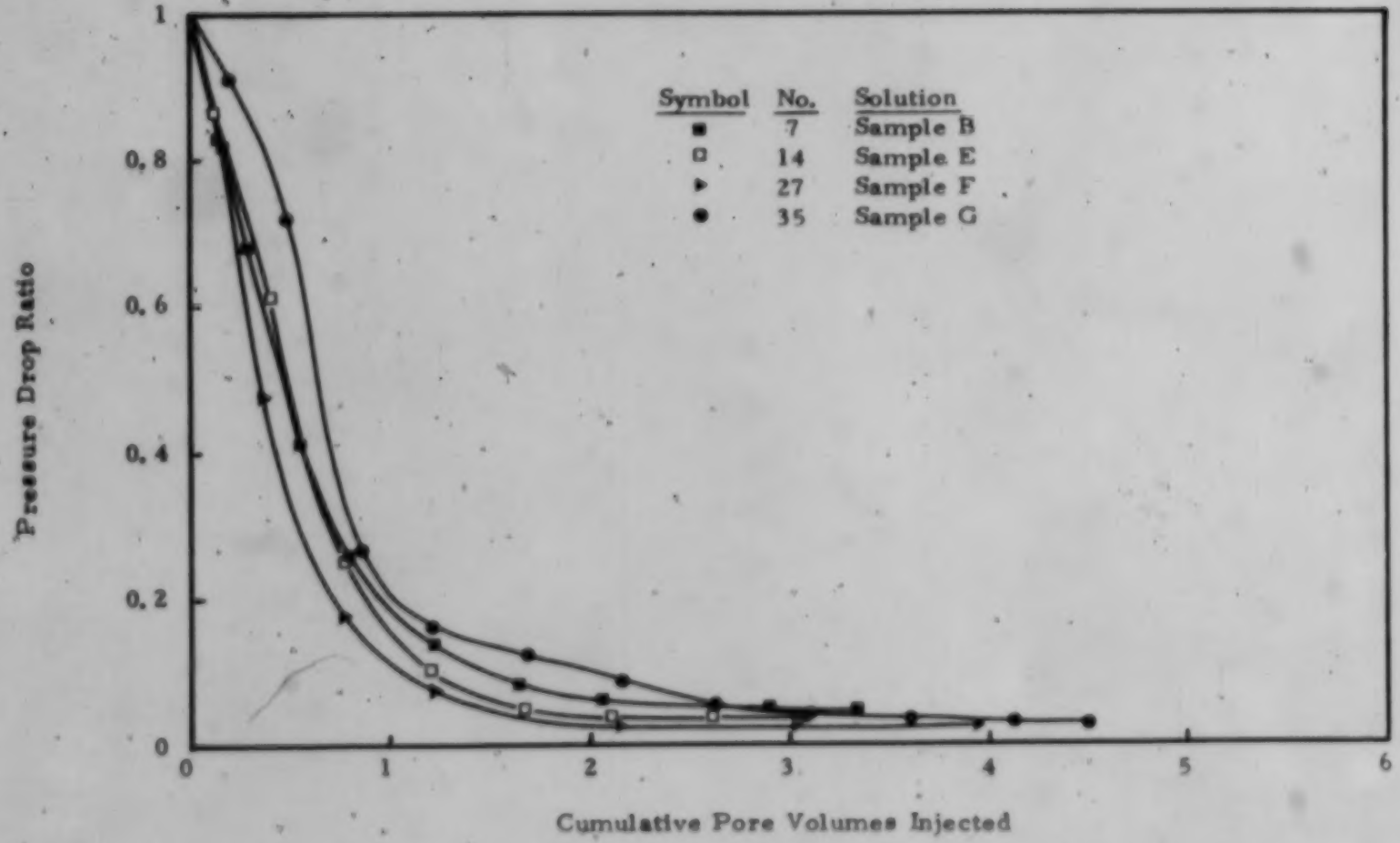


FIG. 20 - PRESSURE BEHAVIOUR FOR SAMPLE SOLUTION DISPLACEMENT TEST

relatively high carboxylate anion contents as well as high pH values.

The results of a series of displacement tests with varying Sample G concentrations in the displacing brine are shown in Figure 21. Sample G floods at concentrations greater than 1% gave significant additional oil recovery over that of a brine flood. However, for Sample G floods at concentrations greater than 9.7%, oil recoveries tend to remain constant. Therefore, the optimum concentration of Sample G in successful floods appears to be in the range 1 - 10%. Sample G floods at concentrations higher than 4% were more effective than sodium hydroxide floods.

In general, displacement tests using Sample G are characterized by the very high recovery at breakthrough and little additional recovery after breakthrough. A 100% Sample G flood appears to be less effective than the brine-Sample G mixture. The absence of sodium chloride in pure Sample G is believed to be responsible for this phenomenon.

Pressure drop ratios during Sample G floods at various concentrations are shown in Figure 22. It is of interest to notice that the pressure drop ratios do not decrease rapidly during tests conducted with Sample G at high concentrations and that the sustained high pressure drop ratios are in full agreement with high breakthrough recoveries. For Tests 18, 20 and 35, the pressure drop ratios during the early stages of floods are sustained at a high level for a

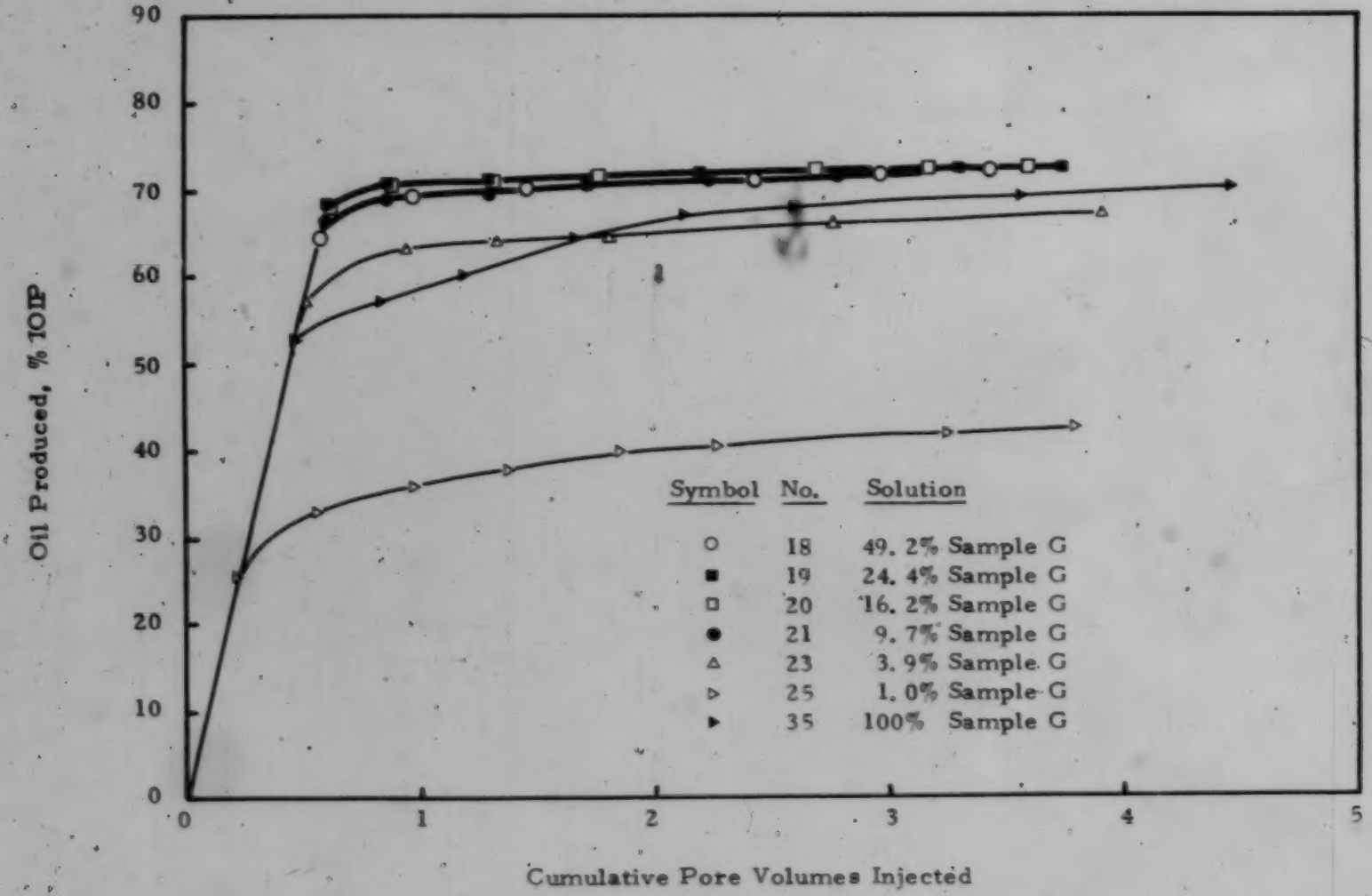


FIG. 21 - OIL RECOVERY FOR SAMPLE G DISPLACEMENT TESTS - SAND 1

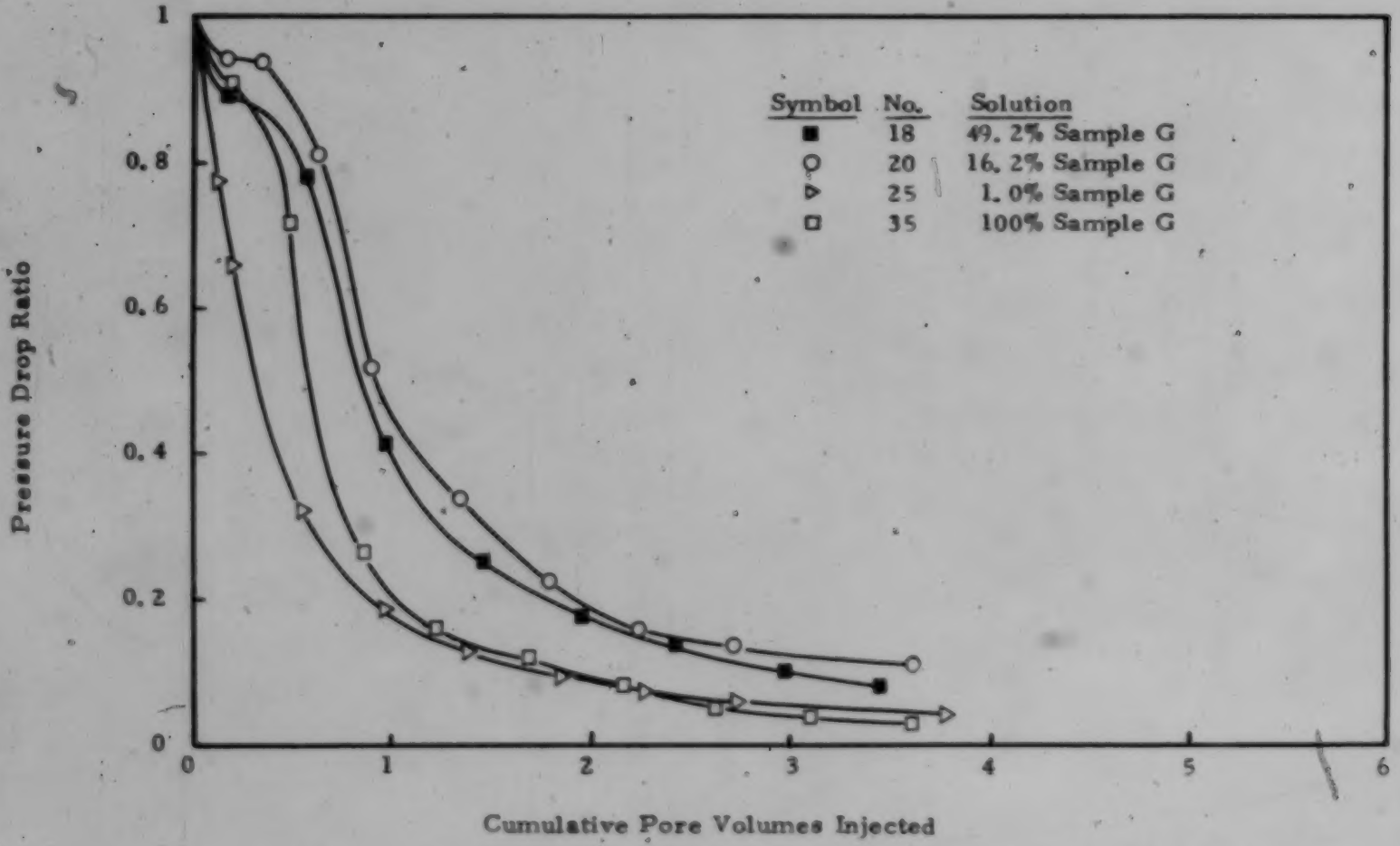


FIG. 22 - PRESSURE BEHAVIOUR FOR SAMPLE G DISPLACEMENT TESTS

given volume of water injected resulting in high oil recovery.

The influence of Sample B concentration on oil recovery is shown in Figure 23. Sample B concentrations higher than 1% exhibit high oil recovery at water breakthrough as well as at 3 PV injected. Sample B at concentrations in the range, 1 - 2% shows increases in oil recovery over that of the 100% Sample B flood. Therefore, the optimum concentration range for Sample B in brine flood appear to be 1 - 20% at which water-oil interfacial tension becomes essentially zero, whereas interfacial tension at a concentration of 100% is 9.4 dynes/cm.

The recovery profile of Sample B flood is characterized by a low breakthrough recovery but a high ultimate recovery. The recovery behaviour of a 100% Sample B flood, however, is similar to that of Sample G with high breakthrough recovery and little additional recovery after that.

Figure 24 shows the effect of Sample E on oil recovery. The 1% Sample E flood shows higher oil recovery than that of a brine flood, but lower recovery than that of a 1% sodium hydroxide flood. Recalling that the pH of sample solutions should be at least 9.5 for satisfactory interfacial tension reduction and that pH values of 1% NaOH and 1% Sample E were 13.2 and 8.6 respectively, one would expect 1% sodium hydroxide to be more effective than 1% Sample E. On the other hand, since Sample E showed a high carboxylic

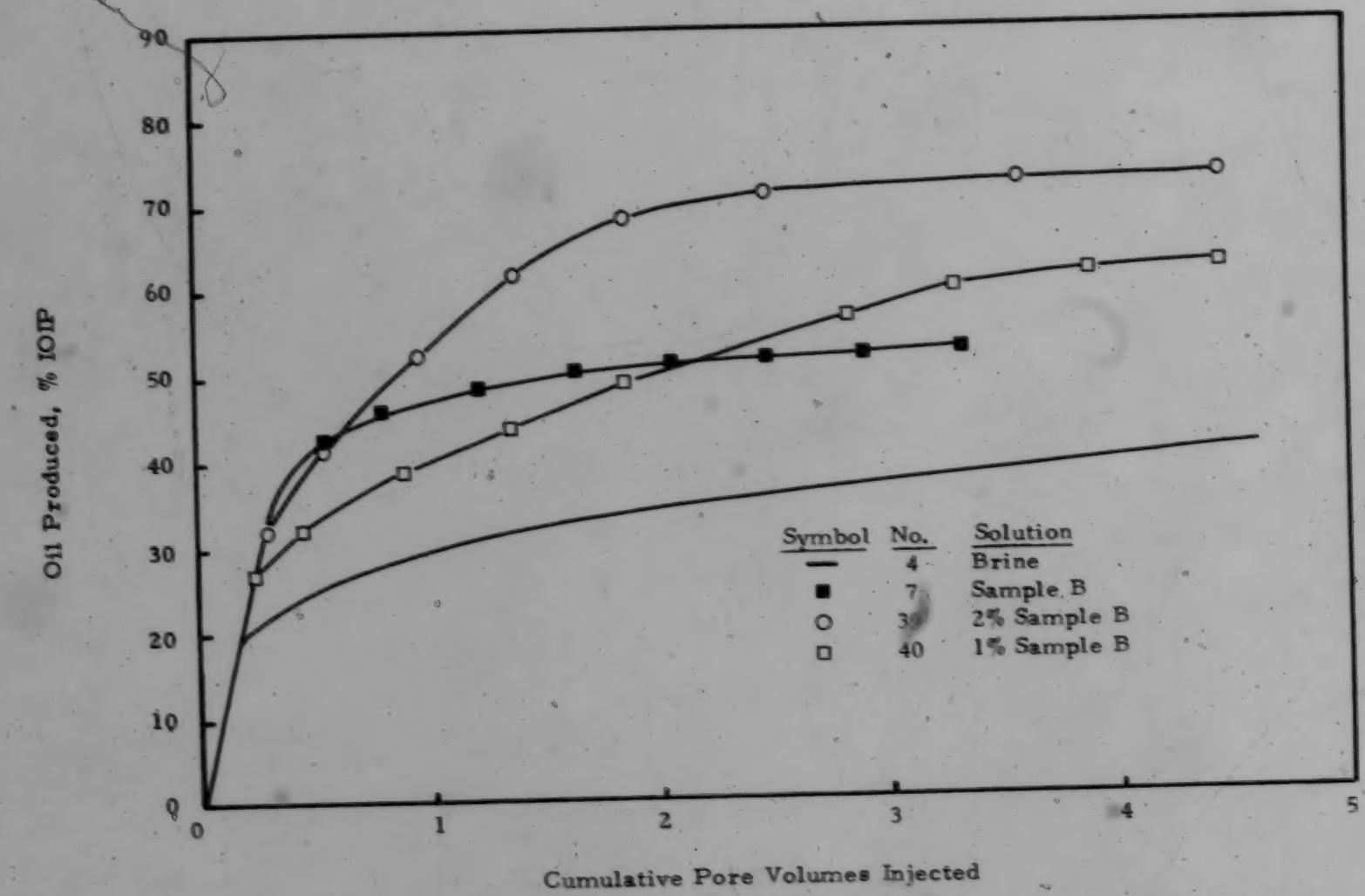


FIG. 23 - OIL RECOVERY FOR SAMPLE B DISPLACEMENT TESTS - SAND 1

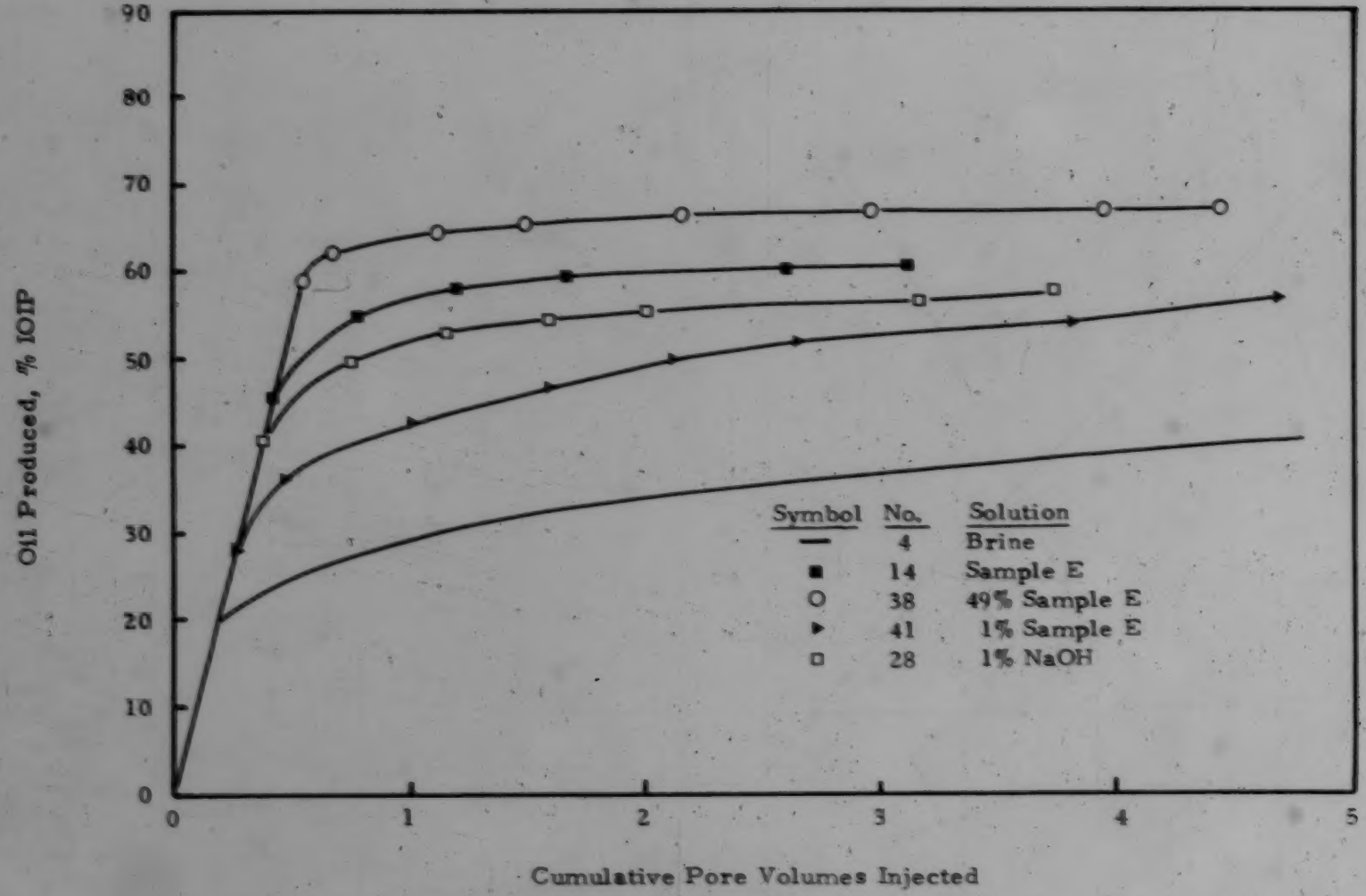


FIG. 24 - OIL RECOVERY FOR SAMPLE E DISPLACEMENT TESTS - SAND 1

acid content in the infrared test, the increase in oil recovery for 1% Sample E over that of a brine flood can be attributed to the role of carboxylate ions. The optimum concentration in successful Sample E floods appears to be in the range, 1 - 50%.

In spite of the relatively high interfacial tension, 3.7 dynes/cm at a concentration of 50%, the Sample E flood exhibited maximum oil recovery at that concentration. This phenomenon may be explained by employing the concepts of dynamic and static interfacial tension. A solution having a surface active agent and whose interface is not in equilibrium will, in general, exhibit an interfacial tension considerably greater than the static tension (117). If the water-oil interface is agitated by mechanical means, the excess concentration of surfactant at the interface will be removed by the turbulence. The interfacial tension at the newly formed interface will then be increased. Therefore, a higher surfactant concentration would be required in a dynamic system to obtain the same reduced interfacial tension obtained in a static system. At Sample E concentration of 20%, the interfacial tension in a static condition was 0.8 dynes/cm. In order to obtain the same interfacial tension in a dynamic system, the concentration of Sample E should be higher than 20%.

For sample solutions such as B, E and G, the 100% sample solutions appear to be less effective. This can be

attributed to the absence of sodium chloride in the pure sample solutions.

The results of displacement tests using combinations of various chemical solutions are shown in Figure 25. Test 10 using 1% sodium hydroxide followed by 1% Alconox recovers little additional oil over 1% sodium hydroxide. Sample B flood followed by Sample G is less effective than Sample G flood followed by Sample B.

In order to determine the recovery efficiency of sample solutions on flooded out cores, delayed Sample G injections into the flooded out cores were conducted. Figure 26 shows delayed Sample G floods conducted at different reinjection pressures and different stages of flooding history. For Test 12, a brine flood was conducted until 4.3 PV injected was attained where the pressure drop across the core was 5.6 psi. Sample G injection was then followed employing a reinjection pressure of 97 psi. For Test 37, the delayed Sample G injection was performed after 4 PV of brine had been injected. The pressure drop at 4 PV injected was 5 psi and the same pressure, 5 psi was used as reinjection pressure. The only difference in conditions between Test 12 and Test 37 is the reinjection pressures, 97 and 5 psi respectively. Therefore, the additional oil recovery in Test 12 over Test 37 can be attributed to the high flow rate due to the high reinjection pressure of Test 12.

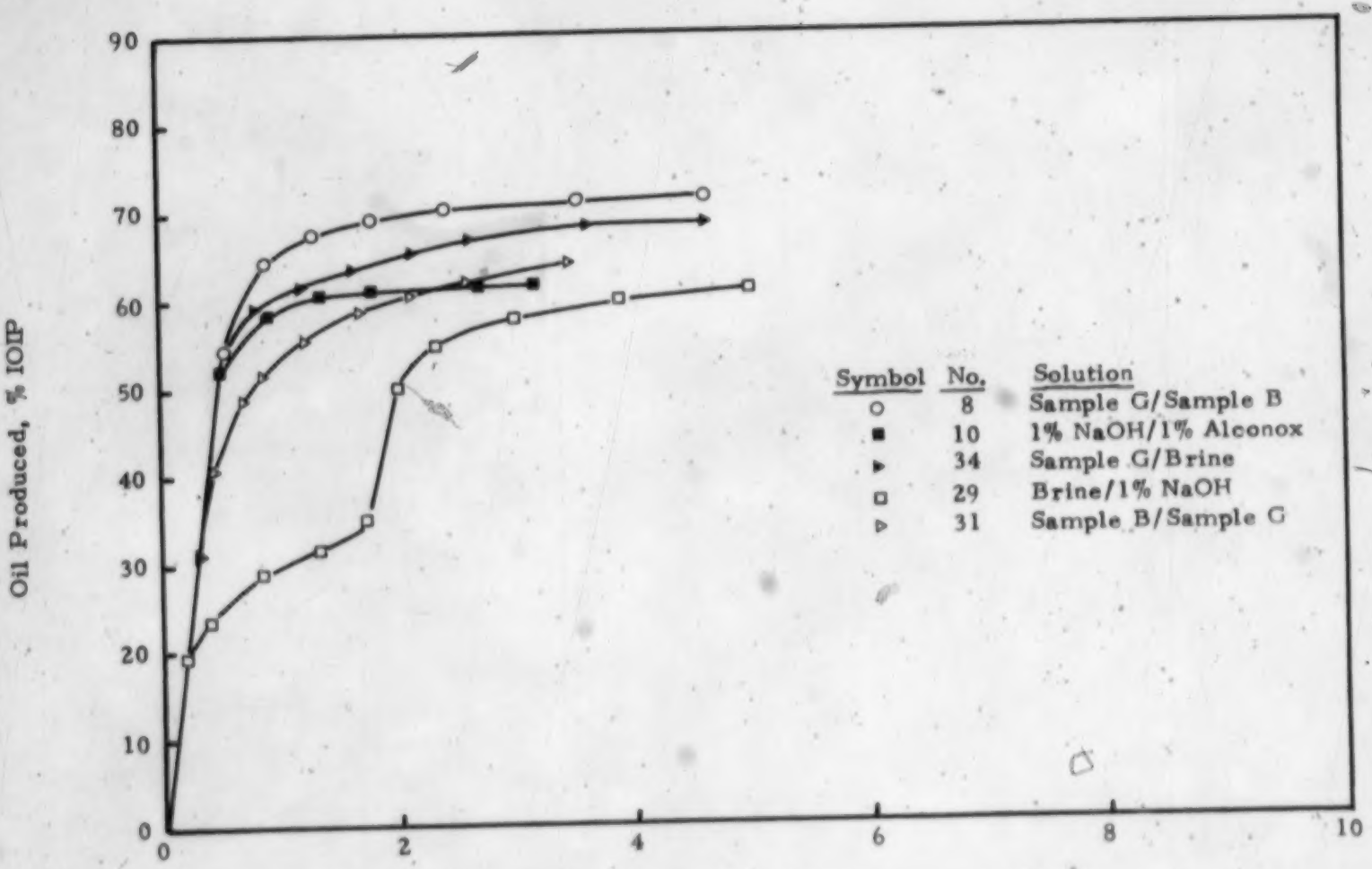


FIG. 25 - EFFECT OF COMBINED INJECTION OF SAMPLES ON OIL RECOVERY

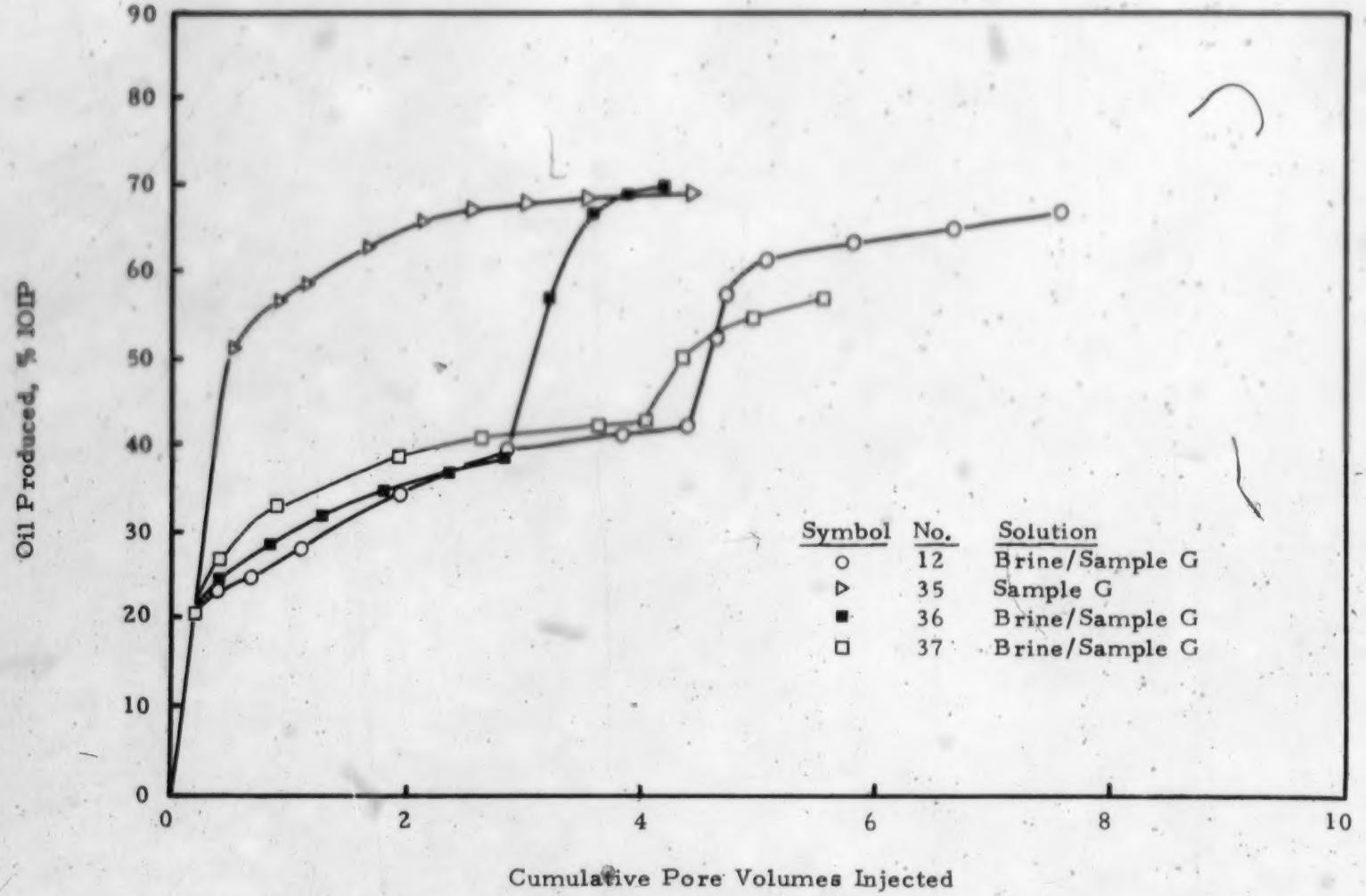


FIG. 26 - EFFECT OF DELAYED INJECTION OF SAMPLE G ON OIL RECOVERY

For Test 36, delayed Sample G injection was started at 2.8 PV injected with the same reinjection pressure, 97 psi as that of Test 12, where the delayed Sample G injection was started at 4.3 PV injected. Additional oil recovery in Test 36 over Test 12, therefore, comes from the difference in the depletion state of cores before the delayed Sample G flood started. Sample G floods in the early stages of development seem more effective than in completely flooded out reservoirs.

Pressure drop ratio plots for Tests 36 and 37 are shown in Figure 27. The reinjection pressure increases immediately after delayed Sample G injection and decreases readily as usual after Sample G breakthrough. As will be discussed later, the increased pressure at the beginning of the delayed sample injection is an indication of the formation of water-in-oil emulsion and in full agreement with the additional oil recovery.

A feasibility test of slug injection was done with Sample G. The result is shown in Figure 28. A 0.22 PV slug of Sample G followed by brine injection shows the practicaly same recovery performace as that of continuous Sample G flood. From an economical point of view, the field application of a sample flood should be based on slug injection rather than continuous injection of pure sample.

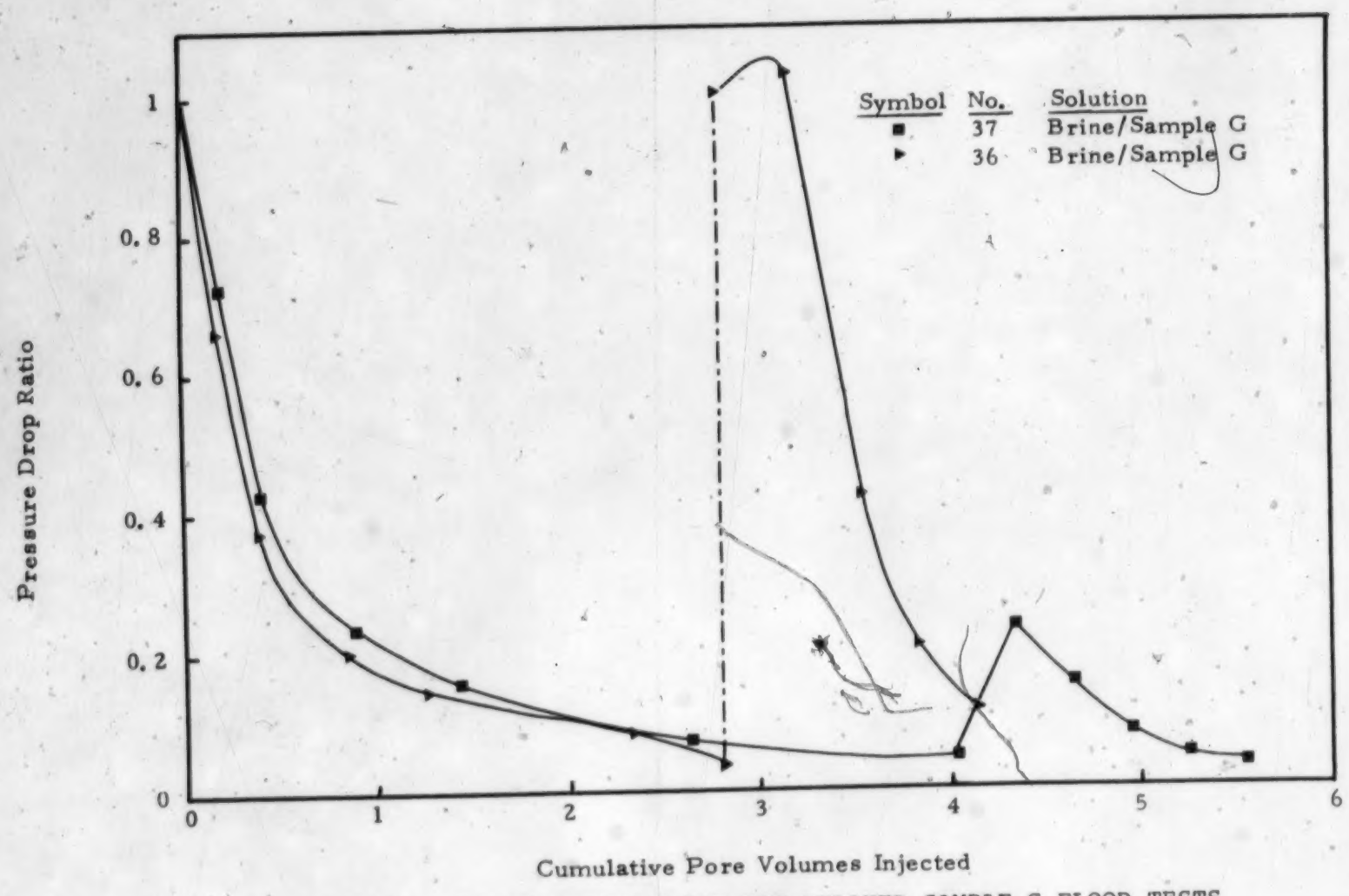


FIG. 27 - PRESSURE BEHAVIOUR FOR DELAYED SAMPLE G FLOOD TESTS

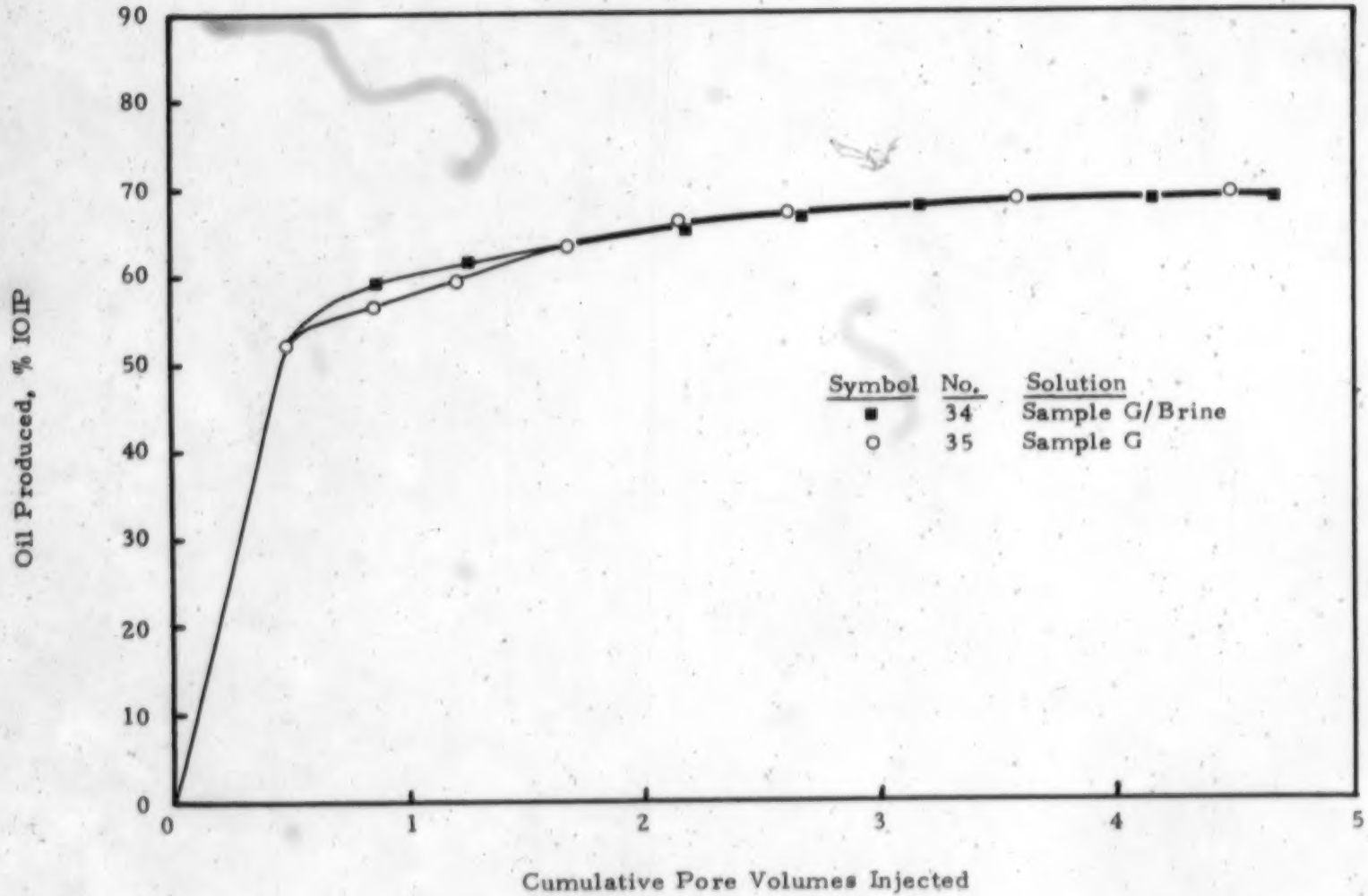


FIG. 28 - EFFECT OF SAMPLE G SLUG ON OIL RECOVERY

Effect of Emulsions on Oil Recovery

During the displacement tests conducted with chemical solutions, the production of stable emulsions was observed. Most of the displacement tests conducted with oil wet Sparky sand produced a water-in-oil type of emulsion, whereas a Triton X-100 flood produced an oil-in-water emulsion.

The type of emulsion depends on various factors such as the relative volumes of the two phases, their relative position, the concentration of the emulsifying agent and the nature of the latter (118). Hence, there is a tendency for water-oil mixtures to form an oil-in-water emulsion when the volume of oil is smaller than that of water and a water-in-oil emulsion when an excess of oil is present. If the walls of the vessel in which the two components are agitated together have been previously wetted with one of them, this liquid tends to be the external phase (119). Therefore, the formation of a water-in-oil emulsion is expected from an oil-in-water emulsion. Cooke et al (120) reported that high salinity also leads to the formation of a water-in-oil type of emulsion.

The viscosity of an emulsion depends very much upon the emulsion type. As was mentioned earlier, the viscosity of emulsions is given by the equation

$$\mu = \mu_e \varepsilon^{k\phi}$$

This equation indicates that the viscosity of an emulsion is a linear function of the viscosity of the external phase, μ_e. If oil is more viscous than water, the viscosity of a water-in-oil emulsion is higher than that of oil-in-water emulsion and vice versa. The viscosity of Lloydminster crude oil is 2800 cp, while that of brine is only 0.993 cp. Therefore, the viscosity of water-in-oil emulsion is apparently higher than that of oil-in-water emulsion.

The increased oil recovery in the successful sample floods in Sparky sand cores can be attributed to the effect of this high viscosity of water-in-oil emulsions. The recovery mechanism in this case can be explained as follows.

By lowering the water-oil interfacial tension, saponification of carboxylic acids naturally occurring in the Lloydminster crude oil gives rise to spontaneous emulsification and stabilization of emulsions formed by mechanical dispersion of water in the oil phase. The presence of surfactants in sample solutions will accelerate this in situ emulsification. Viscous water-in-oil emulsions so formed in the pore spaces effectively close many of the flow paths that were formerly available to the flow of water. As a result of this, an emulsion bank is then formed at the displacement front. The resistance to flow of the emulsion bank causes the large increase in pressure gradient behind the displacement front until the pressure gradient overcomes the

resistance to flow of the emulsion. The emulsion bank then displaces oil very efficiently with the stabilized front reducing viscous fingering and eventually increasing volumetric sweep efficiency.

In support of the formation of the emulsion bank, it is of interest to recall that the pressure drop ratio during the most successful floods did not fall rapidly until water injection reached 0.5 PV (see Fig. 22). Upon further injection, the pressure drop ratio decreased readily.

In the case of the Triton X-100 flood which produced oil-in-water emulsions, the viscosity of an oil-in-water emulsion is higher than that of water. However, the viscosity of this emulsion is nevertheless lower than that of the crude oil. Thus the formation of a stabilized emulsion bank is unlikely to take place, which is indeed confirmed by the monotonically decreasing pressure during the early stages of the flood (see Fig. 16). Therefore, the volumetric sweep efficiency of Triton X-100 flood is very low during the early stages of a displacement test and its breakthrough recovery is very low.

On the other hand, Triton X-100 shows a different recovery mechanism. Since Triton X-100 is a strong wetting agent, oil drops roll up into spheres due to modification of the contact angle resulting in the formation of oil-in-water emulsion. The increased oil recovery at the latter stage of a Triton X-100 flood may be attributed to detergent

action, which leads to wettability reversal of the sand from oil wet to water wet.

Unlike a macro emulsion, a micro emulsion formed by spontaneous emulsification is thermodynamically stable and is micellar in character. Micro emulsions, therefore, give rise to the miscibility of water with oil through solubilization. In many cases, it is difficult to identify the external phase (121). Because of this miscibility , a micro emulsion will displace oil very effectively (122).

In combination with surfactants in the crude oil, the additional surfactants in the sample solutions will, therefore, enhance the formation of the micro emulsions.

CONCLUSIONS

As a result of this investigation, the following conclusions can be made:

1. Some of the waste effluents which have either high surfactant concentrations or high pH values appear to be effective in enhancing oil recovery. Small amounts of Samples B, E, and G in brine showed significant increases in oil recovery over brine flood. However, 100 percent sample solutions were somewhat less effective than the mixture of brine and the sample solutions.

2. The pH of sample solutions required for successful floods should be at least 9.5 to saponify naturally occurring carboxylic acids in the Lloydminster crude oil and eventually to increase oil recovery.

3. Delayed injection of Sample G into a previously flooded out core recovered significant additional oil indicating that Sample G can be used in tertiary recovery.

4. A 0.2 pore volume slug of Sample G appears to be as effective as a continuous Sample G flood. In some cases where the carboxylic acid contents of crude oils are low, it may be advantageous to inject a slug of the sample solutions into a reservoir ahead of the injected water. In so doing, the cost of sample flood could be reduced significantly.

5. Enhanced oil recovery in the successful sample floods can be attributed mainly to the formation of water-in-oil emulsions and their excellent volumetric sweep efficiency with the stabilized emulsion bank front.

6. The effect of emulsion on oil recovery depends upon the type of emulsion. In heavy crude oil reservoirs where the viscosity of the oil is much higher than that of the water, a water-in-oil type of emulsion is more effective than an oil-in-water emulsion.

7. Lloydminster crude oil contains carboxylic acids which form soaps when in contact with alkaline solutions. Samples B, C, E, F, and G contain surfactants, which seem to be related to carboxylate anions.

8. Carboxylate anions appear to be the major contributors to the reduction of water-oil interfacial tension and to in situ emulsification.

9. The effect of inorganic salts on the interfacial tension in ionic surfactant solutions may be elucidated theoreticaly by utilizing Gibb's adsorption equation.

10. The role of reduced capillary pressure, resulting from the low water-oil interfacial tension on the displacement efficiency appears to be insignificant. However, lowering interfacial tension gives rise to in situ emulsification.

NOMENCLATURE

A	=	surface area
a	=	activity
a^+, a^-	=	cationic and anionic activities respectively
$a\pm$	=	mean ionic activity
C	=	concentration
C^+, C^-	=	concentrations of cation and anion respectively
$C\pm$	=	mean ionic concentration
C_t	=	constant, $0.004534 - 1.679\frac{r}{R}$
c	=	constant, about 30
D, d	=	densities of lower and upper phase
e	=	universal constant, 0.7250
F	=	free energy
F^s	=	surface free energy
F_c	=	correction factor for tension measurements
f_w	=	fractional flow of water
g	=	universal constant, 0.0009075
h	=	diameter of core
IOIP	=	initial oil in place
K	=	absolute permeability
K_h	=	hydrolysis constant
K_o	=	effective permeability of oil
K_w	=	effective permeability of water
K_{ro}	=	relative permeability of oil
k	=	constant

L	=	length
n	=	number of moles
n^s	=	number of moles at surface
P	=	pressure
P_c	=	capillary pressure, $P_o - P_w$
P_o	=	pressure in oil phase
P_w	=	pressure in water phase
PV	=	pore volume
R	=	alkyl group
R	=	gas constant
R_r	=	radius of ring
r	=	radius
S	=	entropy
S^s	=	surface entropy
T	=	temperature
T_a	=	apparent surface or interfacial tension
U	=	ionic strength
V	=	volume
V_t	=	total flow rate per unit cross sectional area
Γ	=	adsorption density
γ	=	surface tension or interfacial tension
γ_i	=	total interfacial tension of water-oil system with emulsifiers
γ	=	interfacial tension between water and oil
θ	=	contact angle
λ	=	activity coefficient

λ_+, λ_- = individual ionic activity coefficients

$\lambda\pm$ = mean ionic activity coefficient

μ = chemical potential

μ = viscosity of emulsion

μ_e = viscosity of external phase

μ_o = oil viscosity

μ_w = water viscosity

ν = total number of ions

ν^+, ν^- = number of cations and anions respectively

π = spreading pressure

ϕ = volume fraction of internal phase of emulsion

ψ_{cr} = critical finger distance

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APPENDIX A

MATERIAL PROPERTIES

TABLE A - 1

Sands Properties

Sand Number	Sand Identification
1	Sparky sand from Lloydminster area cleaned with hot water and varsol. Oven dried at 210° F for 10 hours.
2	Ottawa sand 80 - 120 U.S. Mesh in size.

Sieve Analysis of Sparky Sand

Mesh U.S. Series	Weight gr	Weight %	Cumulative Weight %
+35	0.1	0	100
-35 +48	0.3	0.1	100
-48 +65	294.0	62.5	99.9
-65 +100	99.9	21.2	37.4
-100 +150	57.1	12.2	16.4
-150 +200	14.5	3.1	4.1
-200	4.8	1.0	1.0

Atomic Absorption Test of Sparky Sand Employing $LiBO_4$ Fusion Method

Sample No.	Weight	Organic Material	Fe	Mg	Ca
1	0.2010	2.010 gpl	1.95 ppm	0.12 ppm	1.0 ppm
2	0.2030	2.030 gpl	2.0 ppm	0.13 ppm	1.1 ppm
3	0.2028	2.028 gpl	2.0 ppm	0.15 ppm	1.1 ppm

TABLE A - 2

Properties of Oils

Crude Oil

Lloydminster crude oil with water removed.

Density - 0.955 gm/cc

API Gravity - 16.7°

Basic Sediment and Water - 0.1 % by volume

Viscosity Measurement - Weisenberg Rheogoniometer

Shear Rate	RPM	Viscosity	Temperature
6.28	5.68	2843 cp	72° F
3.14	2.84	2843 cp	72° F
0.994	0.9	3119 cp	72° F
0.314	0.284	2843 cp	72° F

Other Oils

Oil	API Gravity (o)	Density (gm/cc)	Mixture Ratio	Viscosity (cp)
Varsol	50.4	0.778	-	0.414
Varsol-crude	44.7	0.803	6 : 1	1.080

TABLE A - 3

Properties of Aqueous Solutions

Brine

Prepared with 84.84 gm of NaCl per liter of solution

Density - 1.053 gm/cc

Viscosity - 0.993 cp

Sample Solutions

Sample	Density	pH	Viscosity (cp)
A	1.001	7.7	1.48
B	1.003	12.6	1.42
C	0.998	9.0	1.43
D	0.997	7.2	1.41
E	1.010	11.4	1.47
F	1.002	9.3	1.42
G	1.020	12.1	1.63

TABLE A - 4

Identification of Chemicals

Inorganic Chemicals

Chemical Name	Chemical Formula
Sodium Chloride	NaCl
Sodium Sulfate	Na_2SO_4
Sodium Hydroxide	NaOH
Sodium Silicate	Na_2SiO_3
Sodium Carbonate	Na_2CO_3

Surfactants

Name	Source
Sodium Oleate	K & K Lab., Inc.
Oleyamine	K & K Lab., Inc.
Alconox	Alconox, Inc.
Triton X-100	Union Carbide, Co.
Sodium Ethylendiamine Tetraacetate (Na_4EDTA)	Aldrich Chem., Co.

APPENDIX B

IMBIBITION AND INTERFACIAL TENSION RESULTS

TABLE B - 1

BENCH TEST RESULTS

Imbibition of Fluids into Dry Sand

Imbibing Fluid	Sand 1	Sand 2
Varsol	SP	SP
Varsol-Crude	SP	SP
Brine	N	SP
0.5% NaOH-Brine	N	SP
0.5% Na_2CO_3-Brine	N	SP
0.5% Na_4EDTA	VSL	SP
0.1% Na-Oleate	SL	SP
1% Na_2SiO_3	N	SP
1% Alconox	SL	SP
1% Triton X-100	SP	SP
Sample A	N	SP
Sample B	N	SP
Sample C	N	SP
Sample D	N	SP
Sample E	N	SP
Sample F	N	SP
Sample G	SL	SP

Imbibition of Fluids into Varsol-Crude Saturated Sand

Imbibing Fluids	Sand 1	Sand 2
Brine	N	N
0.5% NaOH-Brine	SP	SP
0.5% Na_2CO_3-Brine	SL	SL
0.5% Na_4EDTA	SL	SL
0.1% Na-Oleate	SL	SL
1% Na_2SiO_3	SP	SP
1% Alconox	SP	SP
1% Triton X-100	SP	SP
Sample A	N	VSL
Sample B	VSL	SL
Sample C	N	VSL
Sample D	N	VSL
Sample E	VSL	SL
Sample F	N	VSL
Sample G	SP	SP

SP: Spontaneous Imbibition
N: No Imbibition
SL: Slow Imbibition
VSL: Very Slow Imbibition

TABLE B - 2

Summary of Cell Imbibition Test Data

No.	Saturating Fluid	Sand Type	Pore Volume	Imbibed Volume	PV Imbibed(%)	Imbibing Fluid
1	Varsol	1	9.61	0	0	Distilled Water(D. Water)
2	Varsol	1	10.50	0	0	Brine
3	Varsol	1	10.33	0.3	2.9	1% NaOH-Brine
4	Varsol-Crude	1	9.80	0	0	D. Water
5	Varsol-Crude	1	9.61	0	0	Brine
6	Varsol-Crude	1	10.11	1.08	10.68	1% NaOH
7	Varsol-Crude	1	9.73	1.15	11.82	1% NaOH-Brine
8	Varsol-Crude	2	8.32	0	0	Brine
9	Varsol-Crude	2	8.32	4.65	55.90	1% NaOH-Brine
10	Varsol-Crude	1	10.50	1.75	15.52	0.1% NaOH-0.1% Na-Oleate
11	Varsol-Crude	1	9.65	0.25	2.59	1% Na-Oleate
12	Varsol-Crude	1	9.94	0.28	2.82	1% Na_4EDTA-Brine
13	Varsol-Crude	1	10.281	0.6	5.83	0.05% Oleyamine (PH: 2.65)
14	Varsol-Crude	1	10.30	1.51	14.57	1% Alconox
15	Varsol-Crude	1	10.7	1.5	14.01	1% NaOH-Na_2SO_4
16	Varsol-Crude	1	7.79	5.5	71.0	1% Triton x-100
17	Varsol-Crude	1	10.5	0	0	Sample A
18	Varsol-Crude	1	7.9	0.4	5.1	Sample B
19	Varsol-Crude	1	10.7	0.2	1.9	Sample C
20	Varsol-Crude	1	10.3	0	0	Sample D
21	Varsol-Crude	1	7.94	0.5	6.3	Sample E
22	Varsol-Crude	1	10.6	0	0	Sample F
23	Varsol-Crude	1	7.71	0.4	5.2	Sample G

TABLE B - 3

PH AND INTERFACIAL TENSION DATA NO. 1

OIL PHASE VARSOL
WATER PHASE NAOH IN WATER

NAOH CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	5.75	75.6	70.7	31.5	31.2	74.8
0.0020	10.71	75.5	70.6	30.9	30.6	75.1
0.0040	11.05	75.5	70.6	30.9	30.6	75.1
0.0060	11.20	75.5	70.6	30.4	30.0	75.1
0.0080	11.33	75.5	70.6	30.5	30.1	75.1
0.0100	11.45	75.5	70.6	30.4	30.0	75.1
0.0200	11.70	75.6	70.7	29.6	29.2	75.1
0.0400	11.96	75.4	70.5	29.4	28.9	74.8
0.0600	12.15	75.5	70.6	28.8	28.3	74.8
0.0800	12.30	75.5	70.6	30.1	29.7	74.8
0.1000	12.40	75.5	70.6	29.1	28.6	74.8

TABLE B - 4

PH AND INTERFACIAL TENSION DATA NO. 2

OIL PHASE — LLOYDMINSTER
WATER PHASE — NAOH IN WATER

NAOH CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	5.87	75.5	70.6	16.8	19.2	77.6
0.0025	10.69	75.5	70.6	14.7	16.4	77.0
0.0050	11.06	75.1	70.2	10.7	11.4	77.0
0.0075	11.30	75.6	70.7	9.3	9.7	77.0
0.0100	11.40	75.5	70.6	8.2	8.4	77.0
0.0200	11.70	74.4	69.5	3.9	3.7	77.0
0.0400	11.90	74.0	69.1	0.5	0.4	77.0
0.0600	12.15	75.4	70.5	0.5	0.4	77.6
0.0800	12.29	75.3	70.4	0.5	0.4	77.6
0.1000	12.35	75.6	70.7	0.5	0.4	77.6
0.1200	12.45	75.5	70.6	0.5	0.4	77.6
0.2000	12.51	74.9	70.0	0.7	0.6	77.6
0.6000	12.70	73.4	68.5	0.8	0.6	77.6
0.9000	13.10	75.5	70.6	1.2	1.0	77.6
1.1000	13.20	72.9	68.0	1.0	0.8	77.6

TABLE B - 5

PH AND INTERFACIAL TENSION DATA NO. 3

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — NAOH IN BRINE

NAOH CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0020	10.05	78.4	73.2	1.0	0.8	74.0
0.0040	10.75	78.3	73.1	0.5	0.4	74.0
0.0060	10.99	78.4	73.2	0.5	0.4	74.0
0.0080	11.10	78.4	73.2	0.5	0.4	74.0
0.0100	11.21	78.4	73.2	0.5	0.4	74.0
0.0200	11.50	78.6	73.4	0.5	0.4	74.0
0.0400	11.81	78.6	73.4	0.5	0.4	74.0
0.0600	12.10	78.4	73.2	0.5	0.4	74.0
0.0800	12.20	78.4	73.2	0.5	0.4	74.0
0.1000	12.32	78.4	73.2	0.5	0.4	74.0

TABLE B - 6

PH AND INTERFACIAL TENSION DATA NO. 4

OIL PHASE — LLOYDMINSTER
WATER PHASE — NAOH IN NA-OLEATE 0.1 %

NAOH CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	7.50	34.1	30.4	10.0	10.5	73.5
0.0020	8.16	31.8	28.2	8.1	8.2	73.5
0.0040	9.56	30.5	27.0	5.8	5.6	73.5
0.0060	10.64	32.9	29.2	2.9	2.6	73.5
0.0080	10.91	37.0	33.1	1.0	0.8	73.5
0.0100	11.20	37.0	33.1	0.5	0.4	73.5
0.0200	11.50	37.0	33.1	0.5	0.4	73.5
0.0400	11.86	36.9	33.0	0.5	0.4	73.5
0.0600	12.01	36.8	32.9	0.5	0.4	73.5
0.0800	12.15	37.0	33.1	0.5	0.4	73.5
0.1000	12.29	37.0	33.1	0.5	0.4	73.5

TABLE 8 - 7

PH AND INTERFACIAL TENSION DATA NO. 5

OIL PHASE: LLOYDMINSTER CRUDE
WATER PHASE: NA-OLEATE IN BRINE

NA-OLEATE CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0020	7.06	47.8	43.2	12.1	11.8	75.0
0.0060	7.25	42.6	38.3	11.1	10.7	75.0
0.0080	7.18	41.8	37.5	11.1	10.7	75.0
0.0100	7.29	33.7	29.9	4.0	3.5	75.0
0.0200	6.70	31.8	28.2	2.2	1.9	75.0
0.0400	6.50	32.2	28.5	1.5	1.3	75.0
0.0600	6.40	32.2	28.5	1.1	0.9	75.0
0.0800	6.30	31.9	28.3	1.1	0.9	75.0
0.1000	6.25	30.9	27.3	0.7	0.5	75.0

TABLE B - 8

PH AND INTERFACIAL TENSION DATA NO. 6

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — SODIUM SILICATE IN BRINE

SODIUM SILICATE CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0100	9.17	78.7	73.5	2.9	2.5	72.0
0.0200	9.28	78.9	73.7	1.5	1.3	72.0
0.0400	9.40	78.6	73.4	0.6	0.5	72.0
0.1000	9.47	78.5	73.3	0.6	0.5	72.0
0.2500	9.73	79.0	73.8	0.5	0.4	72.0
0.5000	9.92	78.8	73.6	0.5	0.4	72.0
1.0000	10.20	78.7	73.5	0.5	0.4	72.0
2.0000	10.40	78.8	73.5	0.5	0.4	72.0

TABLE B - 9

PH AND INTERFACIAL TENSION DATA NO. 7

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — SAMPLE B IN BRINE

SAMPLE B CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	6.00	78.1	72.9	19.1	19.6	72.0
0.2056	9.25	78.1	72.9	2.5	2.2	72.0
0.5141	10.03	78.1	72.9	0.4	0.3	72.0
1.0281	10.43	78.1	72.9	0.4	0.3	72.0
2.0558	10.80	77.9	72.7	0.4	0.3	72.0
5.1351	11.25	76.9	71.7	0.5	0.4	72.0
20.4532	11.58	76.1	70.9	0.5	0.4	72.0
50.7022	12.21	65.8	60.6	4.3	3.8	72.0
100.0000	12.40	70.4	65.1	10.1	9.4	72.0

TABLE B - 10

PH AND INTERFACIAL TENSION DATA NO. 8

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — SAMPLE E IN BRINE

SAMPLE E CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	6.00	78.1	72.9	19.1	19.6	72.0
0.9595	8.64	77.6	72.4	9.3	8.8	72.0
1.9198	9.00	78.0	72.8	3.1	2.7	72.0
3.8429	9.40	74.5	69.3	0.6	0.5	72.0
4.8056	9.45	70.0	64.9	0.5	0.4	72.0
9.6309	10.06	69.0	63.9	0.5	0.4	72.0
19.3412	10.46	69.0	63.9	1.0	0.8	72.0
48.9578	10.93	61.9	56.9	4.1	3.7	72.0
100.0000	11.33	59.0	54.2	14.5	15.5	72.0

TABLE B - 11

PH AND INTERFACIAL TENSION DATA NO. 9

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — SAMPLE F IN BRINE

SAMPLE F CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	6.00	78.1	72.9	19.1	19.6	72.0
0.4758	9.08	78.0	72.8	2.4	2.1	72.0
1.9049	9.10	77.7	72.5	2.0	1.7	72.0
2.8588	9.10	77.6	72.4	2.3	2.0	72.0
4.7693	9.14	75.1	69.9	1.4	1.2	72.0
9.5619	9.15	64.0	58.9	2.3	2.0	72.0
19.2174	9.18	65.8	60.7	2.4	2.1	72.0
100.0000	9.30	56.9	52.1	5.1	4.9	72.0

TABLE B - 12

PH AND INTERFACIAL TENSION DATA NO.10

OIL PHASE VARSOL
WATER PHASE SAMPLE G IN WATER

SAMPLE G CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
1.0228	10.60	51.0	46.4	24.8	24.0	72.0
2.0451	10.76	45.1	40.8	20.2	19.2	72.0
3.0670	10.80	40.8	36.7	16.1	15.0	72.0
5.0589	11.15	39.8	35.7	13.8	12.7	72.0
7.1499	11.20	38.8	34.8	11.4	10.3	72.0
10.2071	11.30	37.7	33.7	9.3	8.3	72.0
20.3674	11.50	36.0	32.1	6.0	5.2	72.0
50.5701	11.77	34.8	31.0	2.9	2.5	72.0
100.0000	11.99	34.5	30.7	1.4	1.1	72.0

TABLE B - 13

PH AND INTERFACIAL TENSION DATA NO.11

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — SAMPLE G IN WATER

SAMPLE G CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
2.0451	10.86	45.0	40.7	4.0	3.8	71.0
2.5561	10.89	43.7	39.4	2.4	2.2	71.0
3.0670	10.97	42.5	38.3	1.8	1.6	71.0
3.5778	11.00	41.4	37.2	0.8	0.6	71.0
4.0885	11.06	40.1	36.0	0.5	0.4	71.0
4.5990	11.10	40.0	35.9	0.5	0.4	71.0
5.1094	11.15	39.2	35.1	0.5	0.4	71.0
10.2071	11.21	37.8	33.8	0.5	0.4	71.0
50.5701	11.77	34.8	31.0	0.5	0.4	71.0
100.0000	11.99	34.6	30.8	0.5	0.4	71.0

TABLE B - 14

PH AND INTERFACIAL TENSION DATA NO.12

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — SAMPLE G IN BRINE

SAMPLE G CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	6.05	78.3	73.1	19.8	20.4	72.0
0.1937	9.21	45.5	41.0	6.5	6.0	72.0
0.2906	9.50	40.0	35.8	0.8	0.6	72.0
0.4844	9.69	38.9	34.8	0.6	0.5	72.0
0.9689	9.92	35.0	31.1	0.5	0.4	72.0
1.9385	10.35	34.6	30.8	0.5	0.4	72.0
2.9087	10.50	34.2	30.4	0.5	0.4	72.0
100.0000	11.99	34.6	30.8	0.5	0.4	72.0

TABLE B - 15

PH AND INTERFACIAL TENSION DATA NO.13

OIL PHASE — LLOYDMINSTER CRUDE
WATER PHASE — PICKLING SALT WATER

SAMPLE G CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.9689	10.20	37.4	33.4	4.2	3.7	73.0
1.9385	10.40	35.7	31.8	3.7	3.3	73.0
2.9087	10.58	33.9	30.1	3.5	3.1	73.0
3.8795	10.60	33.7	29.9	3.1	2.7	73.0
4.8509	10.73	34.5	30.7	2.5	2.2	73.0
5.8229	10.80	34.9	31.0	1.9	1.6	73.0
6.7955	10.87	34.1	30.3	1.4	1.2	73.0
7.7687	10.90	33.9	30.1	1.3	1.1	73.0
9.7170	11.00	33.9	30.1	1.1	0.9	73.0
14.5985	11.10	33.7	29.9	1.0	0.8	73.0
29.3356	11.37	33.7	29.9	0.5	0.4	73.0
37.2527	11.42	33.7	29.9	0.5	0.4	73.0

TABLE B - 16

PH AND INTERFACIAL TENSION DATA NO.14

OIL PHASE — LLOYDMINSTER
WATER PHASE — TRITON X-100 IN BRINE

TRITON X-100 CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0240	6.00	36.1	32.2	8.1	7.6	72.0
0.0960	6.00	34.3	30.5	4.0	3.5	72.0
0.2400	6.10	34.0	30.2	2.9	2.5	72.0
0.4800	6.00	34.1	30.3	1.9	1.6	72.0
1.2900	6.10	34.1	30.3	1.4	1.2	72.0
2.4000	6.00	34.2	30.4	0.9	0.7	72.0
3.6000	6.00	34.1	30.2	0.9	0.7	72.0

TABLE B - 17

PH AND INTERFACIAL TENSION DATA NO.15

OIL PHASE — VARSOL-OLEIC ACID
WATER PHASE — NAOH IN WATER

NAOH CONCENTRATION WEIGHT PERCENT	PH	SURFACE TENSION APPARENT DYNES/CM	SURFACE TENSION CORRECTED DYNES/CM	INTERFACIAL TENSION APPARENT DYNES/CM	INTERFACIAL TENSION CORRECTED DYNES/CM	TEMPERATURE FAHRENHEIT
0.0000	5.40	73.8	68.9	25.2	24.4	72.0
0.0000	9.00	73.8	68.9	25.1	24.3	72.0
0.0000	10.50	73.8	68.9	13.8	12.7	72.0
0.0000	10.80	73.8	68.9	9.0	8.1	72.0
0.0000	11.08	73.8	68.9	1.5	1.2	72.0
0.0000	11.20	73.8	68.9	0.3	0.2	72.0
0.0000	11.40	73.8	68.9	0.2	0.1	72.0
0.0000	11.70	73.8	68.9	0.2	0.1	72.0
0.0000	12.20	73.8	68.9	0.2	0.1	72.0
0.0000	12.70	73.8	68.9	0.2	0.1	72.0
0.0000	13.10	73.8	68.9	0.2	0.1	72.0
0.0000	13.20	73.8	68.9	4.9	4.2	72.0
0.0000	13.48	73.8	68.9	1.4	1.1	72.0

APPENDIX C

DISPLACEMENT TEST RESULTS

TABLE C - 1

SUMMARY OF DISPLACEMENT TEST

BASIC CORE PROPERTIES

TEST NUMBER	SAND NUMBER	PORE VOLUME CC	POROSITY %	BRINE PERMEABILITY DARCIES	INITIAL WATER SATURATION %	INITIAL OIL IN PLACE CC
1	1	24.5	41.9	13.5	9.8	22.1
2	1	26.5	45.5	21.9	11.2	23.6
3	1	24.3	41.6	14.0	12.7	21.2
4	1	22.6	38.7	15.3	1.1	22.4
5	1	23.3	40.0	12.8	3.6	22.5
6	1	24.5	41.9	13.2	14.2	21.0
7	1	23.9	40.9	12.0	8.9	21.8
8	1	23.1	39.6	11.1	5.9	21.8
9	1	24.1	41.3	9.5	10.8	21.5
10	1	24.6	42.2	9.6	9.2	22.4
11	1	24.4	41.7	10.9	10.2	21.9
12	1	23.5	40.3	8.9	13.3	20.4
13	1	24.0	41.1	8.8	8.8	21.9
14	1	24.2	41.4	11.1	9.1	22.0
15	1	24.5	41.9	11.6	11.0	21.8
16	1	23.5	40.3	9.3	9.1	21.4
17	1	23.8	40.8	13.6	10.2	21.4
18	1	23.8	40.8	11.3	11.9	21.0
19	1	23.2	39.8	9.4	10.6	20.8
20	1	23.3	40.0	12.4	9.2	21.2

TABLE C - 1 (CONTINUED)

TEST NUMBER	SAND NUMBER	PORE VOLUME CC	POROSITY %	BRINE PERMEABILITY DARCIES	INITIAL WATER SATURATION %	INITIAL OIL IN PLACE CC
21	1	23.0	39.5	10.0	11.1	20.5
22	1	24.2	41.5	11.6	0.0	24.2
23	1	23.4	40.1	11.6	9.6	21.2
24	1	23.7	40.6	10.0	8.5	21.7
25	1	24.5	42.1	10.9	11.3	21.8
26	1	24.0	41.1	10.4	11.7	21.2
27	1	23.8	40.8	11.1	9.8	21.5
28	1	23.8	40.8	9.7	8.9	21.7
29	1	24.1	41.3	11.5	7.9	22.2
30	2	25.2	43.2	11.1	18.0	20.7
31	1	25.1	43.0	9.6	13.7	21.7
32	1	24.7	42.4	7.1	7.6	22.9
33	1	23.0	39.5	10.6	8.1	21.2
34	1	23.4	40.1	11.7	7.0	21.8
35	1	24.0	41.1	10.9	9.2	21.8
36	1	24.3	41.6	11.5	8.2	22.3
37	1	24.4	41.7	12.4	8.2	22.4
38	1	24.2	41.4	12.9	8.3	22.2
39	1	24.4	41.7	10.4	9.8	22.0
40	1	24.4	41.7	12.5	11.4	21.6
41	1	23.5	40.3	10.3	6.5	22.0

TABLE C - 2

SUMMARY OF DISPLACEMENT TEST

OIL RECOVERY

TEST NUMBER	OIL RECOVERY AT WATER BREAKTHROUGH PV	OIL RECOVERY AT WATER BREAKTHROUGH IOIP %	OIL RECOVERY AT ONE PORE VOLUME INJECTED PV	OIL RECOVERY AT ONE PORE VOLUME INJECTED IOIP %	OIL RECOVERY AT THREE PORE VOLUME INJECTED PV	OIL RECOVERY AT THREE PORE VOLUME INJECTED IOIP %	TOTAL OIL RECOVERY PV	TOTAL OIL RECOVERY IOIP %	INJECTION FLUID WEIGHT PERCENT
1	0.095	10.6	0.243	26.9	0.306	33.9	0.311	34.4	DISTILLED WATER
2	0.085	9.6	0.182	20.5	0.269	30.3	0.275	31.0	DISTILLED WATER
3	0.133	15.1	0.259	29.8	0.323	37.0	0.333	38.2	BRINE
4	0.200	20.3	0.284	28.7	0.364	36.8	0.415	42.0	BRINE
5	0.149	15.4	0.265	27.6	0.321	33.3	0.367	38.1	BRINE
6	0.550	64.2	0.577	67.3	0.616	71.8	0.617	72.0	49.2 % SAMPLE G
7	0.291	32.0	0.427	46.9	0.474	52.0	0.476	52.3	SAMPLE B
8	0.510	54.3	0.612	65.1	0.664	70.6	0.671	71.4	SAMPLE G / SAMPLE B
9	0.271	30.3	0.396	44.4	0.433	48.6	0.434	48.6	0.5 % ALCONOX
10	0.383	42.2	0.531	58.5	0.557	61.4	0.558	61.5	1 % NAOH / 1 % ALCONOX
11	0.142	15.8	0.252	28.0	0.356	39.7	0.388	43.2	BRINE
12	0.112	12.9	0.236	27.2	0.344	39.7	0.585	67.5	BRINE / SAMPLE G
13	0.142	15.4	0.248	27.2	0.344	37.8	0.399	43.8	FIELD WATER
14	0.412	45.4	0.514	56.6	0.548	60.4	0.549	60.4	SAMPLE F
15	0.433	48.7	0.537	60.4	0.558	62.7	0.558	62.7	1 % SODIUM SILICATE
16	0.607	66.8	0.721	79.3	0.813	89.5	0.815	89.7	1 % SODIUM EDTA
17	0.532	59.2	0.663	73.9	0.746	83.1	0.748	83.4	1 % SODIUM EDTA
18	0.564	64.0	0.606	68.8	0.627	71.2	0.631	71.6	49.2 % SAMPLE G
19	0.607	67.9	0.630	70.4	0.641	71.7	0.642	71.8	24.4 % SAMPLE G
20	0.612	67.4	0.635	70.0	0.654	72.0	0.657	72.4	16.2 % SAMPLE G

TABLE C - 2 (CONTINUED)

TEST NUMBER	OIL RECOVERY AT WATER BREAKTHROUGH PV	OIL RECOVERY AT WATER BREAKTHROUGH IOIP %	OIL RECOVERY AT ONE PORE VOLUME INJECTED PV	OIL RECOVERY AT ONE PORE VOLUME INJECTED IOIP %	OIL RECOVERY AT THREE PORE VOLUME INJECTED PV	OIL RECOVERY AT THREE PORE VOLUME INJECTED IOIP %	TOTAL OIL RECOVERY PV	TOTAL OIL RECOVERY IOIP %	INJECTION FLUID WEIGHT PERCENT
21	0.590	66.4	0.610	68.7	0.631	71.1	0.631	71.1	9.72 % SAMPLE G
22	0.214	21.4	0.299	29.9	0.352	35.2	0.358	35.8	BRINE (100% OIL SAT.)
23	0.515	57.0	0.568	62.9	0.594	65.7	0.601	66.5	3.9 % SAMPLE G
24	0.564	61.7	0.596	65.2	0.632	69.1	0.657	71.8	49.2 % SAMPLE G
25	0.224	25.3	0.313	35.4	0.364	41.1	0.372	42.0	0.97 % SAMPLE G
26	0.516	58.4	0.581	65.8	0.612	69.3	0.620	70.2	16.2 % SAMPLE G
27	0.165	18.3	0.237	26.2	0.258	28.7	0.263	29.2	SAMPLE F
28	0.377	41.4	0.472	51.8	0.515	56.6	0.526	57.8	1 % NAOH
29	0.175	19.0	0.269	29.2	0.527	57.3	0.557	60.5	BRINE / 1 % NAOH
30	0.110	13.5	0.259	31.6	0.428	52.3	0.451	55.0	BRINE
31	0.270	31.3	0.455	52.8	0.539	62.5	0.552	64.0	SAMPLE B / SAMPLE G
32	0.351	38.0	0.470	50.8	0.532	57.5	0.547	59.2	1 % ALCONOX & 1 % NAOH
33	0.195	21.2	0.285	31.0	0.426	46.4	0.539	58.7	1 % TRITON X-100
34	0.485	52.2	0.557	59.9	0.625	67.2	0.636	68.4	SAMPLE G / BRINE
35	0.473	52.2	0.525	57.9	0.617	68.0	0.629	69.3	SAMPLE G
36	0.190	20.8	0.274	29.9	0.432	47.1	0.643	70.1	BRINE / SAMPLE G
37	0.184	20.0	0.304	33.1	0.378	41.2	0.520	56.6	BRINE / SAMPLE G
38	0.540	58.9	0.584	63.7	0.611	66.7	0.614	67.0	49 % SAMPLE F
39	0.284	31.5	0.474	52.6	0.645	71.5	0.653	72.4	2 % SAMPLE B
40	0.233	26.2	0.349	39.5	0.507	57.3	0.552	62.4	1 % SAMPLE B
41	0.263	28.1	0.393	42.1	0.491	52.5	0.530	56.8	1 % SAMPLE F

TABLE C - 3

SUMMARY OF DISPLACEMENT TEST

OIL RECOVERY IN DELAYED FLOOD

TEST NUMBER	OIL RECOVERY AT		NET INCREASE IN RECOVERY IOIP %	2ND PHASE STARTED AT		INJECTION FLUIDS WT %
	THE END OF 1ST PHASE IOIP %	THE END OF 2ND PHASE IOIP %		PV INJECTED FRACTION	INJECTION PRESSURE PSI	
8	56.5	71.4	14.9	0.568	54.0	SAMPLE G / SAMPLE B
10	48.8	61.5	12.7	0.495	56.5	1 % NAOH / 1 % ALCONOX
12	42.3	67.5	25.2	4.377	97.0	BRINE / SAMPLE G
29	34.8	60.5	25.6	1.728	18.5	BRINE / 1 % NAOH
31	31.3	64.0	32.7	0.274	77.1	SAMPLE B / SAMPLE G
34	23.8	68.4	44.6	0.221	98.0	SAMPLE G / BRINE
36	38.7	70.1	31.3	2.831	97.0	BRINE / SAMPLE G
37	42.4	56.6	14.2	4.035	5.0	BRINE / SAMPLE G

TABLE C - 4

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 1

CORE NO.	6.		
PORE VOLUME (CC)	24.5	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.9
BRINE PERMEABILITY (D)	13.5	INITIAL WATER SATURATION (%)	9.8
INITIAL OIL IN PLACE (CC)	22.1	INJECTION RATE(CC)	30.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	DISTILLED WATER

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	99.5	1.000
1.05	0.04	1.05	1.05	0.042	0.047	58.0	0.582
2.35	0.09	1.30	2.35	0.095	0.106	43.3	0.435
3.23	0.13	0.77	3.12	0.127	0.141	37.2	0.373
6.43	0.26	1.10	4.22	0.172	0.190	24.3	0.244
9.68	0.39	0.50	4.72	0.192	0.213	17.3	0.173
14.83	0.60	0.50	5.22	0.213	0.236	10.5	0.105
20.18	0.82	0.50	5.72	0.233	0.258	6.7	0.067
27.28	1.11	0.39	6.11	0.249	0.276	4.1	0.041
34.33	1.40	0.34	6.46	0.264	0.292	2.9	0.029
42.87	1.75	0.29	6.76	0.276	0.306	2.3	0.023
51.77	2.11	0.20	6.96	0.284	0.315	2.1	0.021
60.52	2.47	0.25	7.21	0.294	0.326	2.0	0.020
67.62	2.76	0.19	7.41	0.302	0.335	1.9	0.019
74.83	3.05	0.10	7.52	0.306	0.340	1.9	0.019
82.83	3.38	0.10	7.61	0.311	0.344	1.8	0.018

TABLE C - 5

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 2

CORE NO.	3.		
PORE VOLUME (CC)	26.5	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	45.5
BRINE PERMEABILITY (D)	21.9	INITIAL WATER SATURATION (%)	11.2
INITIAL OIL IN PLACE (CC)	23.6	INJECTION RATE(CC)	30.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	DISTILLED WATER

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	99.0	1.000
1.05	0.03	0.85	0.85	0.031	0.036	70.0	0.707
2.25	0.08	0.97	1.83	0.068	0.077	59.5	0.601
3.20	0.12	0.45	2.27	0.085	0.096	52.4	0.529
6.30	0.23	0.40	2.67	0.100	0.113	35.2	0.355
10.50	0.39	0.69	3.38	0.127	0.143	23.0	0.232
14.30	0.53	0.40	3.77	0.142	0.160	16.0	0.161
19.39	0.72	0.50	4.28	0.160	0.181	10.8	0.109
25.29	0.95	0.50	4.78	0.179	0.202	4.7	0.047
31.79	1.19	0.40	5.18	0.194	0.219	3.2	0.032
39.29	1.47	0.50	5.68	0.213	0.240	2.2	0.022
46.59	1.75	0.29	5.97	0.224	0.253	1.8	0.018
53.69	2.01	0.25	6.22	0.234	0.263	1.8	0.018
60.59	2.27	0.39	6.63	0.249	0.280	1.7	0.017
68.49	2.57	0.30	6.92	0.260	0.293	1.7	0.017
76.49	2.87	0.10	7.03	0.264	0.297	1.7	0.017
84.39	3.17	0.30	7.33	0.275	0.310	1.6	0.016

TABLE C - 6

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 3

CORE NO.	2.		
PORE VOLUME (CC)	24.3	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.6
BRINE PERMEABILITY (D)	14.0	INITIAL WATER SATURATION (%)	12.7
INITIAL OIL IN PLACE (CC)	21.2	INJECTION RATE(CC)	30.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	98.5	1.000
1.00	0.04	1.00	1.00	0.041	0.047	81.1	0.823
1.95	0.08	0.95	1.95	0.080	0.091	73.8	0.749
3.25	0.13	1.29	3.23	0.133	0.152	64.6	0.655
4.63	0.19	0.80	4.04	0.166	0.190	56.4	0.572
9.08	0.37	0.80	4.84	0.199	0.228	35.8	0.363
13.78	0.56	0.60	5.44	0.223	0.256	24.0	0.243
19.62	0.80	0.50	5.94	0.244	0.280	15.7	0.159
25.77	1.06	0.50	6.44	0.264	0.303	10.6	0.107
32.53	1.33	0.30	6.74	0.277	0.317	6.9	0.070
40.12	1.65	0.30	7.04	0.289	0.332	4.2	0.042
47.77	1.96	0.19	7.24	0.297	0.341	2.8	0.028
55.83	2.29	0.19	7.44	0.306	0.350	2.0	0.020
63.93	2.63	0.19	7.64	0.314	0.360	1.8	0.018
71.74	2.95	0.19	7.83	0.322	0.369	1.7	0.017
81.33	3.34	0.10	7.94	0.327	0.374	1.6	0.016
90.83	3.73	0.15	8.10	0.333	0.382	1.5	0.015

TABLE C - 7

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 4

CORE NO.	4.		
PORE VOLUME (CC)	22.6	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	38.7
BRINE PERMEABILITY (D)	15.3	INITIAL WATER SATURATION (%)	1.1
INITIAL OIL IN PLACE (CC)	22.4	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	96.2	1.000
1.45	0.06	1.45	1.45	0.064	0.064	83.6	0.869
3.30	0.14	1.86	3.30	0.146	0.147	71.3	0.741
4.76	0.21	1.24	4.55	0.200	0.203	62.2	0.646
10.16	0.44	0.89	5.45	0.240	0.243	36.8	0.382
16.06	0.70	0.60	6.05	0.267	0.270	22.9	0.238
26.16	1.15	0.59	6.64	0.293	0.296	11.9	0.123
36.26	1.60	0.69	7.34	0.324	0.328	6.7	0.069
47.91	2.11	0.39	7.74	0.342	0.345	4.3	0.044
59.20	2.61	0.29	8.04	0.355	0.359	3.6	0.037
72.00	3.17	0.29	8.34	0.368	0.372	3.4	0.035
84.50	3.73	0.30	8.64	0.381	0.386	3.2	0.033
96.87	4.27	0.27	8.91	0.393	0.398	3.1	0.032
109.17	4.82	0.29	9.21	0.407	0.411	2.9	0.030
121.97	5.38	0.10	9.31	0.411	0.416	2.9	0.030
135.27	5.97	0.10	9.41	0.415	0.420	2.9	0.030

TABLE C - 8

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 5

CORE NO.	5.		
PORE VOLUME (CC)	23.3	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.0
BRINE PERMEABILITY (D)	12.8	INITIAL WATER SATURATION (%)	3.6
INITIAL OIL IN PLACE (CC)	22.5	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	ONP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	98.2	1.000
1.09	0.04	1.09	1.09	0.046	0.048	87.8	0.894
4.29	0.18	2.40	3.48	0.149	0.155	64.8	0.659
8.19	0.35	1.39	4.89	0.209	0.217	44.1	0.449
15.59	0.66	0.80	5.69	0.243	0.252	23.8	0.242
23.79	1.01	0.54	6.23	0.267	0.277	13.6	0.138
32.49	1.39	0.39	6.63	0.284	0.295	8.2	0.083
41.38	1.77	0.30	6.94	0.297	0.308	5.2	0.052
53.58	2.29	0.29	7.23	0.309	0.321	3.1	0.031
65.79	2.81	0.19	7.43	0.318	0.330	2.4	0.024
79.88	3.41	0.19	7.63	0.327	0.339	2.3	0.023
94.13	4.02	0.20	7.83	0.335	0.348	2.1	0.021
104.13	4.45	0.20	8.04	0.344	0.357	2.0	0.020
114.68	4.90	0.14	8.18	0.350	0.363	1.9	0.019
117.98	5.05	0.19	8.38	0.359	0.372	1.9	0.019
127.38	5.46	0.20	8.58	0.367	0.381	1.8	0.018

TABLE C - 9

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 6

CORE NO.	4.		
PORE VOLUME (CC)	24.5	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.9
BRINE PERMEABILITY (D)	13.2	INITIAL WATER SATURATION (%)	14.2
INITIAL OIL IN PLACE (CC)	21.0	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	49.2 % SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DP1
0.00	0.00	0.00	0.00	0.000	0.000	95.0	1.000
4.70	0.19	4.70	4.70	0.191	0.223	91.4	0.962
9.50	0.38	4.81	9.50	0.387	0.452	96.2	1.012
13.59	0.55	3.99	13.49	0.550	0.642	93.5	0.984
24.44	0.99	0.64	14.14	0.577	0.673	43.3	0.455
38.04	1.55	0.39	14.54	0.593	0.692	24.9	0.262
49.44	2.01	0.30	14.84	0.606	0.707	20.1	0.211
62.94	2.56	0.20	15.05	0.614	0.716	17.7	0.186
72.24	2.94	0.04	15.09	0.615	0.718	15.7	0.165
81.64	3.33	0.03	15.12	0.617	0.720	14.0	0.147
84.34	3.44	0.00	15.12	0.617	0.720	14.9	0.156

TABLE C - 10

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 7

CORE NO.	3.		
PORE VOLUME (CC)	23.9	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.9
BRINE PERMEABILITY (D)	12.0	INITIAL WATER SATURATION (%)	8.9
INITIAL OIL IN PLACE (CC)	21.8	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	SAMPLE B

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	98.5	1.000
4.10	0.17	4.10	4.10	0.171	0.188	80.2	0.814
7.00	0.29	2.88	6.97	0.291	0.320	66.6	0.676
13.20	0.55	2.30	9.28	0.387	0.425	40.0	0.406
19.20	0.80	0.70	9.98	0.417	0.457	25.5	0.258
29.35	1.22	0.55	10.53	0.440	0.483	13.3	0.135
39.45	1.64	0.39	10.93	0.456	0.501	7.9	0.080
49.45	2.06	0.20	11.13	0.465	0.510	5.5	0.055
59.34	2.47	0.10	11.23	0.469	0.515	4.9	0.049
69.24	2.89	0.10	11.33	0.473	0.519	4.6	0.046
79.54	3.32	0.07	11.41	0.476	0.523	4.4	0.044

TABLE C - 11

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 8

CORE NO.	3.		
PORE VOLUME (CC)	23.1	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	39.6
BRINE PERMEABILITY (D)	11.1	INITIAL WATER SATURATION (%)	5.9
INITIAL OIL IN PLACE (CC)	21.8	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	SAMPLE G / SAMPLE B

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.2	1.000
4.20	0.18	4.20	4.20	0.181	0.192	81.5	0.838
12.00	0.51	7.64	11.84	0.510	0.543	58.0	0.596
13.17	0.56	0.47	12.32	0.531	0.565	54.0	0.555
13.17	0.56	0.00	12.32	0.531	0.565	54.0	0.555
20.58	0.88	1.70	14.02	0.605	0.643	30.0	0.308
30.04	1.29	0.66	14.67	0.633	0.673	14.9	0.153
41.64	1.79	0.39	15.07	0.650	0.691	10.2	0.104
55.93	2.41	0.20	15.28	0.659	0.700	8.0	0.082
67.83	2.92	0.10	15.38	0.663	0.705	6.4	0.065
82.13	3.54	0.10	15.47	0.668	0.710	5.3	0.054
94.53	4.07	0.16	15.55	0.671	0.713	5.0	0.051
106.93	4.61	0.02	15.57	0.671	0.714	4.8	0.049

TABLE C - 12

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 9

CORE NO.	5.		
PORE VOLUME (CC)	24.1	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.3
BRINE PERMEABILITY (D)	9.5	INITIAL WATER SATURATION (%)	10.8
INITIAL OIL IN PLACE (CC)	21.5	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	0.5 % ALCONOX

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
2.85	0.11	2.85	2.85	0.118	0.132	86.5	0.891
5.85	0.24	3.00	5.85	0.242	0.272	70.9	0.730
6.65	0.27	0.70	6.55	0.271	0.304	65.5	0.675
15.81	0.65	2.46	9.02	0.373	0.419	25.0	0.257
26.52	1.09	0.69	9.71	0.402	0.452	10.5	0.108
35.79	1.48	0.42	10.13	0.420	0.471	5.1	0.052
46.58	1.93	0.20	10.33	0.428	0.480	2.0	0.020
58.08	2.40	0.10	10.43	0.432	0.485	1.4	0.014
69.08	2.86	0.01	10.44	0.433	0.486	1.3	0.013
80.58	3.34	0.02	10.46	0.434	0.486	1.2	0.012

TABLE C - 13

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 10

CORE NO.	6.		
PORE VOLUME (CC)	24.6	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	42.2
BRINE PERMEABILITY (D)	9.6	INITIAL WATER SATURATION (%)	9.2
INITIAL OIL IN PLACE (CC)	22.4	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	1 % NAOH / 1 % ALCONOX

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
2.47	0.10	2.47	2.47	0.100	0.110	84.3	0.869
5.36	0.21	2.90	5.36	0.217	0.239	74.0	0.762
9.77	0.39	4.10	9.46	0.383	0.422	60.0	0.618
12.23	0.49	1.47	10.93	0.443	0.488	56.5	0.582
12.23	0.49	0.00	10.93	0.443	0.488	56.5	0.582
22.41	0.91	2.08	13.02	0.527	0.581	25.0	0.257
33.39	1.35	0.46	13.48	0.546	0.602	9.5	0.097
44.24	1.79	0.14	13.63	0.552	0.608	3.1	0.031
54.74	2.21	0.15	13.68	0.554	0.611	1.2	0.012
66.74	2.70	0.05	13.73	0.556	0.613	0.9	0.009
77.83	3.15	0.14	13.79	0.558	0.615	0.9	0.009

TABLE C - 14

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 11

CORE NO.	3.		
PORE VOLUME (CC)	24.4	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.7
BRINE PERMEABILITY (D)	10.9	INITIAL WATER SATURATION (%)	10.2
INITIAL OIL IN PLACE (CC)	21.9	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
1.70	0.06	1.70	1.70	0.069	0.077	84.0	0.865
3.60	0.14	1.77	3.47	0.142	0.158	68.0	0.701
10.40	0.42	1.50	4.97	0.203	0.226	33.5	0.345
17.40	0.71	0.70	5.67	0.232	0.258	23.2	0.239
27.60	1.13	0.69	6.36	0.260	0.290	16.5	0.170
38.00	1.55	0.60	6.97	0.285	0.318	14.4	0.148
49.39	2.02	0.80	7.77	0.318	0.354	11.7	0.120
60.79	2.49	0.60	8.37	0.342	0.382	10.3	0.106
71.99	2.95	0.29	8.67	0.355	0.395	9.8	0.101
83.69	3.42	0.29	8.97	0.367	0.409	7.8	0.080
98.39	4.03	0.19	9.17	0.375	0.418	7.2	0.074
109.69	4.49	0.29	9.46	0.388	0.432	7.2	0.074

TABLE C - 15

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 12

CORE NO.	4.		
PORE VOLUME (CC)	23.5	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.3
BRINE PERMEABILITY (D)	8.9	INITIAL WATER SATURATION (%)	13.3
INITIAL OIL IN PLACE (CC)	20.4	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE / SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
1.80	0.07	1.80	1.80	0.076	0.089	87.0	0.896
2.80	0.11	0.84	2.64	0.112	0.129	80.0	0.824
9.00	0.38	2.10	4.74	0.201	0.232	40.0	0.412
16.00	0.67	0.30	5.04	0.213	0.247	22.0	0.226
26.00	1.10	0.70	5.74	0.243	0.281	16.0	0.164
35.90	1.52	0.70	6.44	0.273	0.315	12.9	0.132
45.50	1.93	0.59	7.04	0.298	0.345	10.8	0.111
55.39	2.35	0.50	7.54	0.320	0.369	9.1	0.093
66.90	2.84	0.50	8.04	0.341	0.394	7.8	0.080
78.40	3.32	0.20	8.24	0.349	0.403	6.8	0.070
90.09	3.82	0.19	8.44	0.358	0.413	6.2	0.063
103.09	4.37	0.20	8.64	0.366	0.423	5.6	0.057
103.09	4.37	0.00	8.64	0.366	0.423	97.0	1.000
108.99	4.62	2.10	10.73	0.456	0.526	68.0	0.701
110.79	4.70	1.00	11.73	0.498	0.575	57.5	0.592
118.89	5.04	0.79	12.54	0.532	0.614	22.0	0.226

TABLE C - 15(CONTINUED)

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
126.79	5.38	0.19	12.73	0.540	0.624	10.6	0.109
136.49	5.79	0.25	12.98	0.551	0.636	5.3	0.054
146.39	6.21	0.20	13.18	0.560	0.646	4.5	0.046
156.29	6.63	0.10	13.29	0.564	0.651	7.8	0.080
166.99	7.09	0.19	13.48	0.572	0.661	9.7	0.100
177.89	7.55	0.20	13.68	0.581	0.671	6.0	0.061
188.79	8.01	0.10	13.79	0.585	0.675	4.3	0.044

TABLE C - 16

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 13

CORE NO.	5.		
PORE VOLUME (CC)	24.0	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.1
BRINE PERMEABILITY (D)	8.8	INITIAL WATER SATURATION (%)	8.8
INITIAL OIL IN PLACE (CC)	21.9	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	FIELD WATER

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
1.90	0.07	1.90	1.90	0.079	0.086	88.0	0.907
3.60	0.14	1.50	3.40	0.141	0.155	72.2	0.744
9.00	0.37	1.39	4.80	0.199	0.219	47.5	0.489
14.40	0.59	0.69	5.50	0.228	0.251	22.5	0.231
24.60	1.02	0.50	6.00	0.249	0.273	9.5	0.097
34.70	1.44	0.39	6.40	0.266	0.292	5.7	0.058
44.49	1.85	0.70	7.10	0.295	0.324	6.2	0.063
55.59	2.31	0.50	7.60	0.316	0.347	5.6	0.057
66.90	2.78	0.50	8.10	0.337	0.369	5.6	0.057
78.19	3.25	0.39	8.50	0.353	0.388	5.5	0.056
90.49	3.76	0.10	8.60	0.357	0.392	5.5	0.056
103.69	4.31	0.10	8.70	0.362	0.397	5.3	0.054
115.09	4.79	0.89	9.60	0.399	0.438	5.2	0.053

TABLE C - 17

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 14

CORE NO.	1.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	24.2	POROSITY (%)	41.4
SAND TYPE	1.	INITIAL WATER SATURATION (%)	9.1
BRINE PERMEABILITY (D)	11.1	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	22.0	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE SAMPLE E	
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
3.10	0.12	3.10	3.10	0.128	0.140	83.8	0.863
10.10	0.41	6.90	10.00	0.412	0.454	59.0	0.608
19.00	0.78	2.10	12.10	0.499	0.550	24.0	0.247
29.19	1.20	0.69	12.80	0.528	0.581	9.9	0.102
40.39	1.66	0.29	13.09	0.540	0.595	4.7	0.048
51.09	2.11	0.10	13.19	0.545	0.599	3.6	0.037
62.99	2.60	0.05	13.25	0.547	0.602	3.5	0.036
75.29	3.10	0.04	13.30	0.549	0.604	3.5	0.036

TABLE C - 18

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 15

CORE NO.	2.		
PORE VOLUME (CC)	24.5	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.9
BRINE PERMEABILITY (D)	11.6	INITIAL WATER SATURATION (%)	11.0
INITIAL OIL IN PLACE (CC)	21.8	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	1 % SODIUM SILICATE

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
2.80	0.11	2.80	2.80	0.114	0.128	85.0	0.876
10.00	0.40	7.20	10.00	0.408	0.458	56.0	0.577
10.69	0.43	0.62	10.61	0.433	0.487	53.0	0.546
21.10	0.86	2.40	13.02	0.531	0.597	21.2	0.218
32.20	1.31	0.50	13.52	0.551	0.620	8.7	0.089
43.20	1.76	0.07	13.59	0.554	0.623	4.4	0.045
53.89	2.19	0.10	13.69	0.558	0.627	3.5	0.036
64.90	2.64	0.00	13.69	0.558	0.627	3.4	0.035

TABLE C - 19

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 16

CORE NO.	3.		
PORE VOLUME (CC)	23.5	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.3
BRINE PERMEABILITY (D)	9.3	INITIAL WATER SATURATION (%)	9.1
INITIAL OIL IN PLACE (CC)	21.4	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	1 % SODIUM EDTA

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
3.10	0.13	3.10	3.10	0.131	0.144	97.5	1.005
7.20	0.30	4.10	7.20	0.305	0.336	110.5	1.139
14.50	0.61	7.09	14.30	0.607	0.668	83.2	0.857
22.20	0.94	2.50	16.80	0.713	0.785	49.5	0.510
33.20	1.41	1.50	18.30	0.777	0.855	26.5	0.273
47.70	2.02	0.50	18.80	0.798	0.878	13.4	0.138
60.90	2.58	0.29	19.10	0.810	0.892	8.8	0.090
75.70	3.21	0.10	19.19	0.815	0.897	6.8	0.070
89.70	3.80	0.00	19.19	0.815	0.897	6.5	0.067

TABLE C - 20

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 17

CORE NO.	4.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	23.8	POROSITY (%)	40.8
SAND TYPE	1.	INITIAL WATER SATURATION (%)	10.2
BRINE PERMEABILITY (D)	13.6	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	21.4	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE	1 % SODIUM EDTA
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.10	0.17	4.10	4.10	0.172	0.191	86.5	0.891
12.90	0.54	8.60	12.69	0.532	0.593	73.5	0.757
21.80	0.91	2.90	15.59	0.654	0.728	42.0	0.432
33.80	1.41	1.31	16.90	0.709	0.789	17.3	0.178
45.80	1.92	0.40	17.30	0.725	0.808	7.5	0.077
57.90	2.42	0.29	17.60	0.738	0.822	5.0	0.051
70.80	2.97	0.20	17.80	0.746	0.831	3.8	0.039
82.50	3.46	0.04	17.85	0.748	0.834	3.8	0.039

TABLE C - 21

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 18

CORE NO.	5.		
PORE VOLUME (CC)	23.8	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.8
BRINE PERMEABILITY (D)	11.3	INITIAL WATER SATURATION (%)	11.9
INITIAL OIL IN PLACE (CC)	21.0	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	49.7 % SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.25	0.17	4.25	4.25	0.178	0.202	86.7	0.893
13.65	0.57	9.20	13.45	0.564	0.640	75.5	0.778
23.05	0.96	1.00	14.45	0.606	0.688	40.0	0.412
34.65	1.45	0.19	14.65	0.614	0.697	24.3	0.250
46.35	1.94	0.10	14.75	0.618	0.702	17.0	0.175
57.64	2.41	0.11	14.85	0.622	0.707	13.1	0.135
70.54	2.95	0.10	14.95	0.627	0.711	9.7	0.100
81.84	3.43	0.11	15.05	0.631	0.716	7.5	0.077

TABLE C - 22

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 19

CORE NO.	1.		
PORE VOLUME (CC)	23.2	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	39.8
BRINE PERMEABILITY (D)	9.4	INITIAL WATER SATURATION (%)	10.6
INITIAL OIL IN PLACE (CC)	20.8	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	24.4 % SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.18	0.17	4.18	4.18	0.179	0.200	99.5	1.025
9.93	0.42	5.75	9.93	0.426	0.477	103.0	1.061
14.33	0.61	4.20	14.13	0.607	0.679	89.5	0.922
20.33	0.87	0.50	14.63	0.628	0.703	49.5	0.510
30.33	1.30	0.10	14.72	0.633	0.708	27.7	0.285
40.73	1.75	0.10	14.83	0.637	0.712	18.3	0.188
51.23	2.20	0.05	14.88	0.639	0.715	14.7	0.151
63.73	2.73	0.04	14.92	0.641	0.717	13.5	0.139
76.83	3.30	0.01	14.94	0.642	0.718	11.5	0.118
87.23	3.74	0.01	14.95	0.642	0.718	11.2	0.115

TABLE C - 23

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 20

CORE NO.	2.		
PORE VOLUME (CC)	23.3	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.0
BRINE PERMEABILITY (D)	12.4	INITIAL WATER SATURATION (%)	9.2
INITIAL OIL IN PLACE (CC)	21.2	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	16.2 % SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.00	0.17	4.00	4.00	0.171	0.188	91.2	0.940
8.20	0.35	4.20	8.20	0.350	0.386	90.7	0.935
14.60	0.62	6.10	14.30	0.612	0.674	78.5	0.809
21.00	0.89	0.50	14.80	0.633	0.698	50.0	0.515
31.10	1.33	0.19	14.99	0.642	0.707	32.5	0.335
41.60	1.78	0.10	15.09	0.646	0.712	21.6	0.222
51.79	2.21	0.10	15.19	0.650	0.716	15.4	0.158
63.09	2.71	0.04	15.24	0.652	0.719	13.1	0.135
73.99	3.16	0.15	15.30	0.654	0.721	11.3	0.116
84.09	3.59	0.04	15.34	0.657	0.724	10.4	0.107

TABLE C - 24

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 21

CORE NO.	3.		
PORE VOLUME (CC)	23.0	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	39.5
BRINE PERMEABILITY (D)	10.0	INITIAL WATER SATURATION (%)	11.1
INITIAL OIL IN PLACE (CC)	20.5	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	9.72 % SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.20	0.18	4.20	4.20	0.182	0.204	99.1	1.021
8.60	0.37	4.23	8.43	0.365	0.411	98.4	1.014
13.90	0.60	5.20	13.63	0.590	0.664	83.5	0.860
19.70	0.85	0.39	14.03	0.607	0.684	51.4	0.529
29.50	1.27	0.20	14.22	0.616	0.694	27.7	0.285
39.50	1.71	0.20	14.43	0.625	0.703	17.9	0.184
51.50	2.23	0.10	14.53	0.629	0.708	12.1	0.124
63.89	2.76	0.05	14.58	0.631	0.711	9.1	0.093

TABLE C - 25

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 22

CORE NO.	4.		
PORE VOLUME (CC)	24.2	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.5
BRINE PERMEABILITY (D)	11.6	INITIAL WATER SATURATION (%)	0.0
INITIAL OIL IN PLACE (CC)	24.2	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE (100% OIL SAT.)

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
2.70	0.11	2.70	2.70	0.111	0.111	81.0	0.835
5.30	0.21	2.50	5.20	0.214	0.214	63.5	0.654
15.70	0.64	1.80	7.00	0.288	0.288	24.0	0.247
28.00	1.15	0.39	7.40	0.304	0.304	12.0	0.123
38.10	1.56	0.39	7.80	0.321	0.321	8.7	0.089
50.20	2.06	0.29	8.10	0.333	0.333	6.8	0.070
64.50	2.65	0.29	8.40	0.345	0.345	5.7	0.058
79.79	3.28	0.29	8.69	0.358	0.358	5.5	0.056

TABLE C - 26

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 23

CORE NO.	5.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	23.4	POROSITY (%)	40.1
SAND TYPE	1.	INITIAL WATER SATURATION (%)	9.6
BRINE PERMEABILITY (D)	11.6	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	21.2	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE	3.9 % SAMPLE G
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.20	0.17	4.20	4.20	0.179	0.198	91.5	0.943
8.50	0.36	4.30	8.50	0.362	0.400	83.8	0.863
12.69	0.54	3.60	12.09	0.515	0.570	69.8	0.719
21.80	0.92	1.19	13.29	0.567	0.627	41.9	0.431
31.19	1.33	0.20	13.49	0.575	0.636	36.9	0.380
42.00	1.79	0.10	13.59	0.579	0.641	16.0	0.164
52.89	2.25	0.20	13.80	0.588	0.650	9.9	0.102
64.90	2.76	0.10	13.90	0.592	0.655	6.6	0.068
77.29	3.29	0.10	14.00	0.596	0.660	5.0	0.051
91.29	3.89	0.10	14.10	0.601	0.665	4.1	0.042

TABLE C - 27

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 24

CORE NO.	2.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	23.7	POROSITY (%)	40.6
SAND TYPE	1.	INITIAL WATER SATURATION (%)	8.5
BRINE PERMEABILITY (D)	10.0	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	21.7	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE	49.2 % SAMPLE G
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
9.90	0.41	9.90	9.90	0.416	0.456	79.7	0.821
13.80	0.58	3.50	13.40	0.564	0.617	70.7	0.728
19.60	0.82	0.59	13.99	0.589	0.645	46.5	0.479
29.80	1.25	0.39	14.39	0.606	0.663	26.0	0.268
43.20	1.81	0.20	14.59	0.614	0.672	15.0	0.154
56.79	2.39	0.19	14.79	0.623	0.682	12.5	0.128
70.40	2.96	0.19	14.99	0.631	0.691	11.2	0.115
85.69	3.60	0.10	15.09	0.636	0.695	10.1	0.104
100.69	4.24	0.30	15.39	0.648	0.709	8.3	0.085
114.99	4.84	0.20	15.59	0.657	0.718	7.7	0.079

TABLE C - 28

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 25

CORE NO.	3.		
PORE VOLUME (CC)	24.5	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	42.1
BRINE PERMEABILITY (D)	10.9	INITIAL WATER SATURATION (%)	11.3
INITIAL OIL IN PLACE (CC)	21.8	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	0.97 % SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.00	0.16	4.00	4.00	0.162	0.183	75.0	0.773
5.95	0.24	1.52	5.52	0.224	0.253	63.5	0.654
14.45	0.58	1.60	7.12	0.289	0.326	31.0	0.319
24.55	0.99	0.59	7.71	0.313	0.354	17.7	0.182
34.65	1.40	0.39	8.11	0.330	0.372	12.2	0.125
46.25	1.88	0.50	8.61	0.350	0.395	8.8	0.090
56.45	2.29	0.10	8.71	0.354	0.399	6.8	0.070
67.95	2.76	0.20	8.92	0.362	0.409	5.4	0.055
80.54	3.27	0.09	9.02	0.366	0.413	4.3	0.044
93.84	3.81	0.14	9.16	0.372	0.420	3.6	0.037

TABLE C - 29

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 26

CORE NO.	4.		
PORE VOLUME (CC)	24.0	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.1
BRINE PERMEABILITY (D)	10.4	INITIAL WATER SATURATION (%)	11.7
INITIAL OIL IN PLACE (CC)	21.2	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	16.2 % SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.10	0.17	4.10	4.10	0.170	0.193	98.3	1.013
8.20	0.34	4.10	8.20	0.341	0.386	98.6	1.016
12.60	0.52	4.20	12.40	0.516	0.584	90.9	0.937
20.70	0.86	1.39	13.79	0.574	0.650	51.3	0.528
30.70	1.27	0.50	14.29	0.595	0.674	26.1	0.269
40.60	1.68	0.11	14.39	0.599	0.679	16.7	0.172
50.89	2.11	0.10	14.49	0.603	0.683	12.1	0.124
60.99	2.53	0.09	14.59	0.607	0.688	10.0	0.103
71.09	2.95	0.09	14.69	0.611	0.693	9.1	0.093
81.29	3.38	0.10	14.79	0.615	0.698	8.6	0.088
91.79	3.82	0.05	14.84	0.618	0.700	8.5	0.087
102.39	4.26	0.04	14.89	0.620	0.702	8.7	0.089

TABLE C - 30

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 27

CORE NO.	5.		
PORE VOLUME (CC)	23.8	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.8
BRINE PERMEABILITY (D)	11.1	INITIAL WATER SATURATION (%)	9.8
INITIAL OIL IN PLACE (CC)	21.5	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	SAMPLE F

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.10	0.17	3.95	3.95	0.165	0.183	80.2	0.826
8.50	0.35	1.30	5.25	0.220	0.244	45.5	0.469
18.60	0.78	0.29	5.54	0.232	0.258	16.2	0.167
29.10	1.22	0.20	5.75	0.241	0.267	6.7	0.069
40.40	1.69	0.10	5.85	0.245	0.272	2.9	0.029
51.78	2.17	0.18	6.03	0.252	0.280	2.0	0.020
62.58	2.62	0.10	6.13	0.257	0.285	2.0	0.020
72.98	3.06	0.05	6.18	0.259	0.287	2.0	0.020
83.48	3.50	0.05	6.23	0.261	0.289	2.0	0.020
94.77	3.97	0.04	6.28	0.263	0.292	1.9	0.019

TABLE C - 31

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 28

CORE NO.	1.		
PORE VOLUME (CC)	23.8	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.8
BRINE PERMEABILITY (D)	9.7	INITIAL WATER SATURATION (%)	8.9
INITIAL OIL IN PLACE (CC)	21.7	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	1 % NAOH

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
5.40	0.22	5.40	5.40	0.226	0.248	85.7	0.883
9.30	0.39	3.60	9.00	0.377	0.414	75.8	0.781
18.05	0.75	1.85	10.85	0.455	0.500	47.5	0.489
27.95	1.17	0.70	11.55	0.484	0.532	30.5	0.314
38.05	1.59	0.29	11.85	0.497	0.546	20.8	0.214
48.05	2.01	0.20	12.05	0.505	0.555	15.0	0.154
61.05	2.56	0.10	12.15	0.509	0.559	10.3	0.106
75.55	3.16	0.20	12.35	0.518	0.569	7.6	0.078
89.15	3.74	0.19	12.55	0.526	0.578	11.1	0.114

TABLE C - 32

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 29

CORE NO.	2.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	24.1	POROSITY (%)	41.3
SAND TYPE	1.	INITIAL WATER SATURATION (%)	7.9
BRINE PERMEABILITY (D)	11.5	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	22.2	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE	BRINE / 1 % NAOH
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
2.90	0.12	2.90	2.90	0.120	0.130	85.2	0.878
4.30	0.17	1.33	4.23	0.175	0.190	78.2	0.806
9.30	0.38	1.00	5.23	0.217	0.236	53.3	0.549
21.10	0.87	1.10	6.34	0.262	0.285	30.2	0.311
32.30	1.33	0.60	6.94	0.287	0.312	22.6	0.232
41.70	1.72	0.80	7.74	0.320	0.348	18.5	0.190
41.70	1.72	0.00	7.74	0.320	0.348	18.5	0.190
48.59	2.01	3.30	11.04	0.457	0.497	38.5	0.396
56.49	2.34	1.10	12.14	0.503	0.546	31.0	0.319
72.69	3.01	0.59	12.73	0.528	0.573	17.2	0.177
83.19	3.44	0.30	13.04	0.540	0.587	12.6	0.129
93.99	3.89	0.20	13.24	0.548	0.596	9.6	0.098
105.49	4.37	0.10	13.34	0.553	0.600	8.2	0.084
120.89	5.01	0.10	13.44	0.557	0.605	6.8	0.070

TABLE C - 33

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 30

CORE NO.	6.		
PORE VOLUME (CC)	25.2	TEMPERATURE (F)	80.0
SAND TYPE	2.	POROSITY (%)	43.2
BRINE PERMEABILITY (D)	11.1	INITIAL WATER SATURATION (%)	18.0
INITIAL OIL IN PLACE (CC)	20.7	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
3.20	0.12	2.80	2.80	0.110	0.135	80.0	0.824
8.40	0.33	1.30	4.10	0.162	0.198	53.8	0.554
17.40	0.68	1.00	5.10	0.201	0.246	31.5	0.324
26.60	1.05	1.69	6.79	0.269	0.328	26.8	0.276
36.70	1.45	1.69	8.49	0.336	0.410	21.2	0.218
46.79	1.85	1.50	9.99	0.395	0.483	16.7	0.172
57.49	2.27	0.39	10.39	0.411	0.502	10.2	0.105
68.40	2.70	0.30	10.69	0.423	0.516	6.5	0.067
79.49	3.14	0.19	10.89	0.431	0.526	4.4	0.045
90.79	3.59	0.10	10.99	0.435	0.531	2.8	0.028
102.29	4.04	0.20	11.19	0.443	0.541	2.0	0.020
113.79	4.50	0.20	11.40	0.451	0.550	1.8	0.018

TABLE C - 34

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 31

CORE NO.	3.		
PORE VOLUME (CC)	25.1	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	43.0
BRINE PERMEABILITY (D)	9.6	INITIAL WATER SATURATION (%)	13.7
INITIAL OIL IN PLACE (CC)	21.7	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	SAMPLE B / SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	ONP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
6.90	0.27	6.80	6.80	0.270	0.313	77.1	0.794
6.90	0.27	0.00	6.80	0.270	0.313	77.1	0.794
11.40	0.45	2.00	8.80	0.349	0.405	73.0	0.752
17.40	0.69	1.80	10.60	0.421	0.488	52.8	0.544
22.20	0.88	0.59	11.19	0.445	0.516	40.2	0.414
32.10	1.27	0.89	12.09	0.480	0.557	25.5	0.262
43.29	1.72	0.69	12.79	0.508	0.589	16.0	0.164
54.49	2.16	0.39	13.19	0.524	0.608	8.5	0.087
65.40	2.59	0.20	13.39	0.532	0.617	7.3	0.075
76.40	3.03	0.20	13.59	0.540	0.626	4.7	0.048
87.49	3.47	0.29	13.89	0.552	0.640	4.0	0.041

TABLE C - 35

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 32

CORE NO.	4.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	24.7	POROSITY (%)	42.4
SAND TYPE	1.	INITIAL WATER SATURATION (%)	7.6
BRINE PERMEABILITY (D)	7.1	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	22.9	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE	1 % ALCONOX & 1 % NAOH
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	ONP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.3	1.000
4.00	0.16	4.00	4.00	0.161	0.174	77.7	0.798
8.30	0.33	4.26	8.26	0.333	0.360	64.3	0.660
8.91	0.35	0.45	8.71	0.351	0.380	62.5	0.642
14.20	0.57	1.79	10.52	0.424	0.459	46.5	0.477
24.20	0.97	1.10	11.61	0.468	0.507	28.5	0.292
33.91	1.36	0.60	12.21	0.493	0.533	20.0	0.205
46.70	1.88	0.39	12.61	0.509	0.551	14.4	0.147
62.00	2.50	0.39	13.02	0.525	0.569	11.6	0.119
76.70	3.09	0.19	13.21	0.533	0.577	10.3	0.105
90.20	3.63	0.10	13.31	0.537	0.581	9.2	0.094
100.45	4.05	0.15	13.46	0.543	0.588	8.5	0.087
112.25	4.52	0.10	13.57	0.547	0.592	8.3	0.085

TABLE C - 36

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 33

CORE NO.	4.		
PORE VOLUME (CC)	23.0	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	39.5
BRINE PERMEABILITY (D)	10.6	INITIAL WATER SATURATION (%)	8.1
INITIAL OIL IN PLACE (CC)	21.2	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	1 % TRITON X-100

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DP1
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.90	0.21	4.50	4.50	0.195	0.212	80.0	0.824
12.00	0.52	1.30	5.80	0.251	0.273	50.1	0.516
22.45	0.97	0.75	6.55	0.283	0.308	38.2	0.393
33.05	1.43	0.50	7.05	0.305	0.332	19.5	0.201
44.85	1.94	0.89	7.95	0.344	0.375	16.6	0.171
57.35	2.48	1.10	9.05	0.392	0.426	13.6	0.140
67.10	2.90	0.65	9.70	0.420	0.457	11.7	0.120
77.00	3.33	0.70	10.40	0.450	0.490	10.0	0.103
86.84	3.76	0.64	11.05	0.478	0.521	8.7	0.089
97.34	4.21	0.50	11.55	0.500	0.544	7.4	0.076
106.94	4.63	0.39	11.95	0.517	0.563	6.3	0.064
119.04	5.15	0.50	12.45	0.539	0.587	5.5	0.056

TABLE C - 37

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 34

CORE NO.	2.		
PORE VOLUME (CC)	23.4	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	40.1
BRINE PERMEABILITY (D)	11.7	INITIAL WATER SATURATION (%)	7.0
INITIAL OIL IN PLACE (CC)	21.8	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	SAMPLE G / BRINE

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
5.20	0.22	5.20	5.20	0.221	0.238	98.0	1.010
5.20	0.22	0.00	5.20	0.221	0.238	98.0	1.010
11.60	0.49	6.20	11.40	0.485	0.522	88.7	0.914
20.40	0.86	1.50	12.90	0.549	0.591	51.1	0.526
29.40	1.25	0.50	13.40	0.571	0.614	24.9	0.256
39.60	1.68	0.39	13.80	0.588	0.633	14.3	0.147
51.20	2.18	0.39	14.19	0.605	0.651	9.0	0.092
62.70	2.67	0.30	14.50	0.618	0.665	5.0	0.051
74.45	3.17	0.25	14.75	0.628	0.676	4.7	0.048
86.04	3.66	0.09	14.84	0.633	0.681	4.2	0.043
97.54	4.15	0.05	14.90	0.635	0.683	3.8	0.039
109.54	4.67	0.03	14.93	0.636	0.684	3.5	0.036

TABLE C - 38

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 35

CORE NO.	3.		
PORE VOLUME (CC)	24.0	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.1
BRINE PERMEABILITY (D)	10.9	INITIAL WATER SATURATION (%)	9.2
INITIAL OIL IN PLACE (CC)	21.8	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.90	0.20	4.88	4.88	0.203	0.223	88.2	0.909
11.70	0.48	6.51	11.38	0.473	0.522	69.5	0.716
20.60	0.85	1.00	12.38	0.515	0.567	25.6	0.263
29.00	1.20	0.60	12.97	0.540	0.595	15.6	0.160
40.30	1.67	0.89	13.88	0.577	0.636	11.7	0.120
51.70	2.15	0.60	14.47	0.602	0.664	8.1	0.083
62.79	2.61	0.19	14.67	0.610	0.673	5.0	0.051
74.09	3.08	0.20	14.88	0.619	0.682	3.7	0.038
86.29	3.59	0.10	14.97	0.623	0.687	3.1	0.031
98.59	4.10	0.10	15.08	0.627	0.691	2.6	0.026
107.89	4.49	0.04	15.12	0.629	0.693	2.4	0.024

TABLE C - 39

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 36

CORE NO.	5.		
PORE VOLUME (CC)	24.3	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.6
BRINE PERMEABILITY (D)	11.5	INITIAL WATER SATURATION (%)	8.2
INITIAL OIL IN PLACE (CC)	22.3	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE / SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DP1
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.80	0.19	4.64	4.64	0.190	0.208	63.8	0.657
9.90	0.40	0.94	5.58	0.229	0.250	36.3	0.374
20.50	0.84	0.79	6.38	0.262	0.286	19.7	0.203
31.25	1.28	0.82	7.21	0.296	0.323	14.3	0.147
43.90	1.80	0.60	7.81	0.321	0.350	10.7	0.110
57.47	2.36	0.53	8.34	0.343	0.373	8.2	0.084
68.83	2.83	0.29	8.64	0.355	0.387	3.2	0.032
68.83	2.83	0.00	8.64	0.355	0.387	97.0	1.000
77.83	3.20	4.10	12.74	0.524	0.571	99.5	1.025
86.73	3.56	2.20	14.94	0.614	0.669	41.0	0.422
94.08	3.86	0.44	15.39	0.633	0.690	20.0	0.206
101.52	4.17	0.25	15.64	0.643	0.701	11.3	0.116

TABLE C - 40

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 37

CORE NO.	4.		
PORE VOLUME (CC)	24.4	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.7
BRINE PERMEABILITY (D)	12.4	INITIAL WATER SATURATION (%)	8.2
INITIAL OIL IN PLACE (CC)	22.4	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	BRINE / SAMPLE G

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.60	0.18	4.50	4.50	0.184	0.200	70.5	0.726
9.60	0.39	1.40	5.90	0.241	0.263	41.5	0.427
21.60	0.88	1.40	7.30	0.299	0.325	23.0	0.237
34.80	1.42	0.60	7.90	0.323	0.352	15.2	0.156
47.30	1.93	0.70	8.60	0.352	0.383	11.1	0.114
64.30	2.63	0.50	9.10	0.372	0.406	7.6	0.078
76.50	3.13	0.19	9.30	0.381	0.415	5.7	0.058
88.79	3.63	0.10	9.40	0.385	0.419	4.5	0.046
98.49	4.03	0.10	9.50	0.389	0.424	4.7	0.048
98.49	4.03	0.00	9.50	0.389	0.424	5.0	0.051
105.89	4.33	1.60	11.10	0.454	0.495	22.7	0.234
113.29	4.64	0.69	11.80	0.483	0.526	15.0	0.154
120.69	4.94	0.39	12.20	0.499	0.544	8.0	0.082
128.09	5.24	0.19	12.40	0.508	0.553	4.8	0.049
135.39	5.56	0.29	12.69	0.520	0.566	3.5	0.036

TABLE C - 41

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 38

CORE NO.	6.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	24.2	POROSITY (%)	41.4
SAND TYPE	1.	INITIAL WATER SATURATION (%)	8.3
BRINE PERMEABILITY (D)	12.9	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	22.2	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE	49 % SAMPLE E
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED WI (CC)	FLUID INJECTED WI (PV)	RECOVERY DNP (CC)	RECOVERY NP (CC)	CUMULATIVE OIL PV	CUMULATIVE OIL IOIP	PRESSURE DROP DP (PSI)	PRESSURE DROP DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
10.40	0.42	10.40	10.40	0.429	0.468	72.0	0.742
13.40	0.55	2.70	13.10	0.540	0.590	61.5	0.634
16.50	0.68	0.70	13.80	0.569	0.621	46.6	0.480
27.30	1.12	0.50	14.30	0.590	0.644	17.8	0.183
36.30	1.49	0.20	14.50	0.598	0.653	8.8	0.090
45.30	1.87	0.18	14.68	0.606	0.661	4.2	0.043
52.30	2.15	0.05	14.72	0.608	0.663	2.5	0.025
59.70	2.46	0.05	14.78	0.610	0.665	2.2	0.022
71.70	2.96	0.03	14.81	0.611	0.667	2.1	0.021
83.70	3.45	0.02	14.83	0.612	0.668	2.1	0.021
95.70	3.95	0.03	14.86	0.613	0.669	2.0	0.020
107.70	4.44	0.02	14.88	0.614	0.670	2.0	0.020

TABLE C - 42

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 39

CORE NO.	1.		
PORE VOLUME (CC)	24.4	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.7
BRINE PERMEABILITY (D)	10.4	INITIAL WATER SATURATION (%)	9.8
INITIAL OIL IN PLACE (CC)	22.0	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	2 % SAMPLE B

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
6.00	0.24	6.00	6.00	0.245	0.272	64.5	0.664
7.30	0.29	0.94	6.94	0.284	0.315	59.4	0.612
13.50	0.55	2.10	9.04	0.370	0.410	41.6	0.428
23.70	0.97	2.40	11.44	0.468	0.520	30.0	0.309
34.00	1.39	2.10	13.54	0.554	0.615	24.9	0.256
45.70	1.87	1.39	14.94	0.612	0.679	18.1	0.186
60.59	2.48	0.60	15.54	0.636	0.706	10.2	0.105
72.29	2.96	0.19	15.73	0.644	0.715	7.1	0.073
87.59	3.58	0.10	15.84	0.649	0.720	4.8	0.049
98.09	4.01	0.05	15.89	0.651	0.722	4.2	0.043
108.99	4.46	0.05	15.94	0.653	0.724	3.8	0.039

TABLE C - 43

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 40

CORE NO.	2.		
PORE VOLUME (CC)	24.4	TEMPERATURE (F)	80.0
SAND TYPE	1.	POROSITY (%)	41.7
BRINE PERMEABILITY (D)	12.5	INITIAL WATER SATURATION (%)	11.4
INITIAL OIL IN PLACE (CC)	21.6	INJECTION RATE(CC)	40.0
OIL VISCOSITY (CP)	2800.	WATER VISCOSITY (CP)	0.993
OIL	LLOYDMINSTER CRUDE	INJECTED PHASE	1 % SAMPLE B

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DP1
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
4.80	0.19	4.80	4.80	0.196	0.222	75.0	0.773
6.00	0.24	0.90	5.70	0.233	0.263	68.6	0.707
11.20	0.45	1.20	6.90	0.282	0.319	46.0	0.474
22.00	0.90	1.39	8.30	0.340	0.384	25.8	0.265
33.30	1.36	1.10	9.40	0.385	0.435	18.3	0.188
45.40	1.86	1.09	10.49	0.430	0.486	15.7	0.161
58.00	2.37	0.94	11.44	0.469	0.530	13.6	0.140
69.31	2.83	0.70	12.14	0.497	0.562	12.4	0.127
80.59	3.31	0.70	12.84	0.526	0.594	11.3	0.116
94.89	3.88	0.39	13.24	0.542	0.613	8.4	0.086
108.79	4.45	0.10	13.34	0.546	0.618	6.7	0.069
120.79	4.94	0.15	13.40	0.549	0.620	5.3	0.054
137.80	5.64	0.09	13.48	0.552	0.624	4.5	0.046

TABLE C - 44

DISPLACEMENT TEST RECOVERY DATA - TEST NO. 41

CORE NO.	3.	TEMPERATURE (F)	80.0
PORE VOLUME (CC)	23.5	POROSITY (%)	40.3
SAND TYPE	1.	INITIAL WATER SATURATION (%)	6.5
BRINE PERMEABILITY (D)	10.3	INJECTION RATE(CC)	40.0
INITIAL OIL IN PLACE (CC)	22.0	WATER VISCOSITY (CP)	0.993
OIL VISCOSITY (CP)	2800.	INJECTED PHASE	1 % SAMPLE E
OIL	LLOYDMINSTER CRUDE		

FLUID INJECTED		RECOVERY		CUMULATIVE OIL		PRESSURE DROP	
WI (CC)	WI (PV)	DNP (CC)	NP (CC)	PV	IOIP	DP (PSI)	DP/DPI
0.00	0.00	0.00	0.00	0.000	0.000	97.0	1.000
5.20	0.22	5.20	5.20	0.220	0.236	76.9	0.792
6.60	0.28	1.00	6.20	0.263	0.281	70.6	0.727
11.80	0.50	1.80	8.00	0.339	0.363	49.4	0.509
24.70	1.04	1.39	9.40	0.399	0.427	24.9	0.256
38.40	1.63	0.89	10.30	0.437	0.468	15.0	0.154
50.70	2.15	0.71	11.00	0.467	0.499	11.2	0.115
62.89	2.67	0.39	11.40	0.484	0.518	8.7	0.089
76.59	3.25	0.29	11.69	0.496	0.531	7.7	0.079
90.49	3.84	0.20	11.90	0.505	0.540	5.0	0.051
111.09	4.71	0.59	12.49	0.530	0.568	5.0	0.051